Science and Technology

Assessing Natural Gas and Oil Resources

An Example of a New Approach in the Greater Green River Basin

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PREFACE

This report presents a new approach to assessing natural gas and crude oil resources and the results of applying that approach to the Greater Green River Basin in southwestern Wyoming. The methodology builds upon existing assessments of technically recoverable resources by evaluating economic and environmental considerations and including these into the assessment as additional resource attributes. The primary objectives of this effort are to inform government officials and other stakeholders involved in land use planning, development of energy policies, and energy development and utilization planning. The approach aims to guide strategic (i.e., large-scale and long-term) planning, and is not intended to replace existing project-specific economic or land use planning processes. The initial framework for this approach was presented in two earlier reports:

- *Assessing Gas and Oil Resources in the Intermountain West: Review of Methods and Framework for a New Approach,* RAND MR-1553-WFHF (2002).
- *A New Approach to Assessing Gas and Oil Resources in the Intermountain West,* RAND IP-225-WFHF (2002).

This report should be of interest to federal, state, and local government land managers; and it is also expected to be useful to producers and the associated investment community, electric and natural gas utilities, and state planning agencies to help guide strategic business planning, improve long-term forecasting, and foster dialog among stakeholders. The study was funded by the William and Flora Hewlett Foundation.

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SUMMARY

Natural gas demand in the United States has been increasing for the last 15 years and is projected to grow substantially in the next 20 years. Meeting this growing demand will require an accompanying increase in supply, which is expected to come mostly from additional production in the United States. The prospect of increased U.S. production has led to ongoing efforts both to better assess our nation's natural gas resources and to develop policies for identifying and developing available resources.

Such efforts are drawing attention to the intermountain areas of the Rocky Mountains, which are relatively rich in hydrocarbon resources, particularly natural gas. National resource assessments indicate that the Rockies contain approximately 15 percent of the nation's technically recoverable (resources plus reserves) future natural gas supply. Although production in the region currently accounts for only about 9 percent of the natural gas produced in the United States, this figure is increasing rapidly as demand increases and resources in more established regions—such as Texas and the Gulf Coast—are depleted.

In the Rockies, 60 percent of the potential gas underlies federal land, compared to just 2 percent in the onshore areas of Texas and the Gulf Coast states. Thus, growth in production in the Rockies means that energy-related land use decisions will increasingly become the responsibility of federal land managers from such agencies as the Bureau of Land Management and the Forest Service. Given the rapid increase in natural gas production in the Rocky Mountains, it is increasingly important for these agencies to take a strategic view of federal land use decisionmaking—one that allows them to understand the differences between resources in different areas and thus to prioritize lands under consideration for development.

ASSESSING NATURAL GAS AND OIL RESOURCES

Federal land use planning is the process by which priorities for various land uses are established. This process incorporates a variety of considerations and attempts to weigh the merits of multiple resources (commodities or uses that the land may provide), including energy resource development and other consumptive uses, environmental management and conservation, and protection of recreational and cultural resources. The values of various resources are determined in a variety ways and documented in resource assessments. Such resource assessments play an important role in the land use planning process.

In the case of natural gas and oil, resource assessments historically focus on the amount of resource. However, additional attributes of energy resources affect the energy resource value of an area. A comprehensive assessment would include as much information about the resource as possible to help distinguish among resources in different areas. Attributes of energy resources that influence their value include the following:

- How much resource might be recoverable,
- How much resource might be available at different costs, and
- How much resource is associated with lands having different values of key environmental measures.

In this report, we present a new approach for assessing natural gas and oil resources that incorporates these elements. This methodology provides a more complete understanding of energy resource characteristics than conventional assessments do, by accounting for the economics, or real dollar costs, associated with production and by moving some of the environmental protection considerations, or social costs, upstream in the decisionmaking process. The key steps in our approach are shown in Figure S.1.

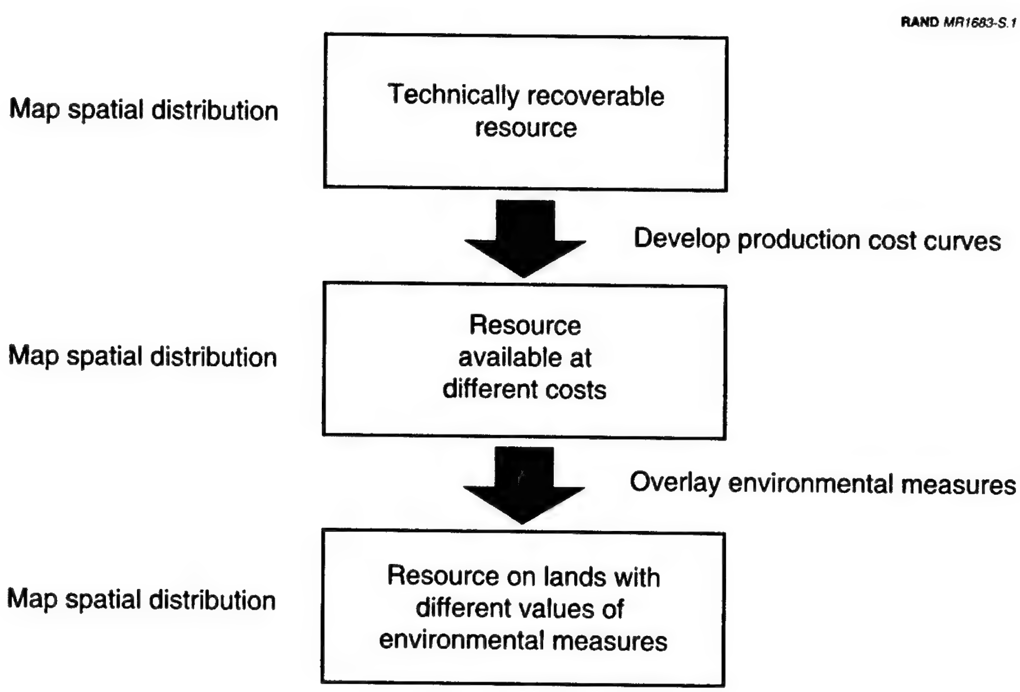

Figure S.1—Summary of Approach

In addition to helping inform the federal land use planning process, the comprehensive resource assessment proposed in this study is intended to improve decisionmaking in a number of other arenas. Potential benefits of this approach in these different areas are summarized below.

Federal Land Use Planning

The proposed assessment approach could help distinguish among lands with similar amounts of natural gas or oil. Areas with similar amounts of technically recoverable resources may have very different amounts of economically recoverable resource. Similarly, areas can be classified according to how much of the resource is on lands that are potentially more vulnerable to negative environmental impacts. Together, this information would further characterize energy resources and could help inform the process of setting priorities for energy-related land use decisions.

National Energy Planning

Assessing the merits of different policy options, such as increasing energy efficiency standards, investing in energy technologies, or pursuing expanded production would be facilitated with an understanding of the costs associated with each. Assessing the economically recoverable resources would help constrain costs and returns associated with production, which are currently unclear.

Production costs also exert a strong influence on fuel choices and amounts of fuel imports. Planning for future energy supplies thus strongly depends on estimates of energy resource production costs.

States, Utilities, and Producers

As states become more dependent on natural gas for electricity generation, state planners need to understand the resource potential. Prices from various potential sources are influenced by the amount of resource at different production costs. Similarly, utilities, many of which are making long-term investments in gas-fired power plants, could make better investment decisions with this type of information.

Economic Effects of Resource Extraction

An understanding of the economically recoverable resource as well as the potential environmental concerns associated with its production may also help define the effect that energy resource production might have on the local, regional, and national economies. A realistic understanding of the economic impacts at all scales depends on the amount of development and production activity that will actually occur.

ADVANTAGES AND LIMITATIONS

The proposed assessment approach can help federal and state land managers and policymakers at all levels set priorities and strategically plan for long-term resource use. Several aspects of this methodology are new and offer supplementary benefits to decisionmakers. Our approach

- Treats economic costs and environmental characteristics as integral attributes of energy resources that affect their value,
- Links the economic analysis with the spatial analysis, enabling decisionmakers to consider relative priorities for development based on the economic viability of the resource,
- Overlays the distribution of resources under various economic assumptions with distributions of environmental characteristics of lands associated with energy resources,
- Is intended to be applicable to other areas of the Rocky Mountains as well as to other regions of the nation, and
- Offers an additional tool for energy forecasters to provide further spatial and temporal refinements to their long-term resource estimates.

At the same time, this approach is preliminary in several aspects and has limitations and uncertainties. It is designed to enhance and supplement the regional assessment of gas and oil resources for the purposes of strategic (long-term and large-scale) planning of energy resource development on public lands. The method is not intended to be used to replace detailed economic or environmental analyses on specific leases. Also, this approach is intended to be part of a broader set of information sources used by decisionmakers in guiding land use and other energy development–related policy. We do not intend to define particular areas where drilling may be inappropriate. Rather, our intent is to provide a framework for assessing the value of energy resources.

Several assumptions are embedded in the spatial distribution of resources, production cost functions, and overlay analyses. Sensitivity of the results to these assumptions is an important consideration in interpreting the results. Also, uncertainties about the effect of gas or oil development on environmental measures mean that these overlays should be used to signal the need for further study and analysis of likely impacts and opportunities for mitigation.

NATURAL GAS IN THE GREATER GREEN RIVER BASIN

We have initially applied this method to the Greater Green River Basin, located primarily in southwestern Wyoming. The Greater Green River Basin contains substantial amounts of natural gas, with estimates of resources plus reserves of 135 to 160 trillion cubic feet (Tcf). This constitutes approximately 10 percent of the nation's total. Our results for this region reflect a reasonable range of assumptions regarding economic and environmental considerations. These results, which are summarized

in Table S.1, are instructive for developing the methodology further and providing insights that may help inform strategic energy resource planning in this basin.

Economic Analysis

By estimating separate costs for each resource unit ("subplay"), resource category, resource type, and depletion increment, separate costs were estimated for over 1,200 distinct analysis units throughout the basin. The analysis indicates that, depending on the economic scenario, 35 to 45 percent of the natural gas resources could be produced profitably at a market price of $3/MMBtu, which is similar to recent prices in Wyoming. Up to 65 percent could be profitably produced if the market price were $5/MMBtu.

The spatial analysis shows that the fraction of technically recoverable gas that is economically recoverable at a given price varies substantially from place to place. This result illustrates the value of the combination of economic and spatial analyses: When looking at specific areas, the concentrations of economically recoverable resources does not necessarily correlate directly with the concentrations of technically recoverable resources. This is illustrated in Maps 2.2 and 3.1 in the maps section, which show these concentrations. The circles highlight an example of an area where the difference between the concentration of technically recoverable and economically recoverable gas is considerably greater than the basinwide average, whereas the squares show an area where the concentrations of technically and economically recoverable gas are very similar.

Table S.1

Summary of Results

		Cost ($/MMBtu)	
		3	5
Economically recoverable gas	Tcf:	47–68	70–104
	% of TRR:	35–45	52–65
Percentage of economically recoverable gas on lands			
With high terrestrial vertebrate species richness[a]		17	17
Within 2,000 m of sensitive species locations		14	14
Within 6,500 m of sensitive species locations		65	65
With surface water, wetlands, or riparian habitats		9	10
Near human settlements		5	6
With high surface slope[b]		8	8
With high aquifer recharge rate[c]		9	9
With shallow groundwater[d]		9	10
Subject to no access[e]		10	10
Subject to restricted access[e]		31	30

NOTES: Ranges for economically recoverable gas reflect different economic scenarios. Results for environmental measures are for the USGS-based scenario only; percentages shown do not necessarily apply to separate areas and so are not additive.

[a]>119 species/area.

[b]>25%.

[c]>2 inches/year.

[d]<16 feet.

[e]Results are based on aggregated lease stipulations from the Department of Energy study (Advanced Resources International, Inc., 2001) and are not related to environmental measures analyzed in this study.

Environmental Considerations

The environmental measures analysis provides additional understanding of the gas resources in the Greater Green River Basin. In this analysis, we examined seven environmental measures:

- Terrestrial vertebrate species richness,
- Proximity to sensitive species observed locations,
- Surface water and riparian habitat zones,
- Proximity to human settlements,
- Surface slope,
- Aquifer recharge rate,
- Depth to groundwater.

The first three measures address primarily ecosystem quality, the fourth represents issues related to human use of the area, and the final three measures examine primarily water quality. We also considered land that is subject to existing federal land access restrictions. Measure values were grouped into bins defined primarily by the statistics of the data for the basin, as well as regulatory and scientific considerations in some cases. Maps of the spatial distribution of the lands with different measure values were then generated. Note that using statistically derived bin values does provide a relative sense of environmental concern for this specific area, and in so doing provides useful guidance. However, because these values are not based on empirically derived relationships between gas and oil development activities and potential environmental impacts, they say little about actual environmental risk and in that sense the environmental measures need to be developed further.

The relative proportion of economically recoverable gas on lands having different values of environmental measures is presented in Table S.1. For the most part, the concentrations of economically recoverable gas are in areas having relatively lower potential environmental concern with respect to the environmental measures we considered. As with the economic evaluation, however, environmental overlay results for certain areas within the basin differ from the basinwide average values shown in Table S.1. Some areas with relatively high gas concentrations coincide with riparian habitats, high terrestrial vertebrate species richness, and shallow groundwater. Such insights may be particularly useful in areas, such as north of the LaBarge Platform, that may appear quite promising judging by the economic analysis alone.

The connection between environmental measures and sensitivity to environmental impact is complex, and actual environmental impacts would not necessarily result from development in areas of nominally greater environmental concern. However, our results suggest that in some areas there may be more costs associated with mitigating potential impacts than in some other regions. This information would be useful to public land managers who may need to prioritize their efforts in permitting lands for exploration and production.

The results generated from this approach can provide decisionmakers with more information about natural resources that can help guide strategic resource planning, help prioritize difficult decisions that are being made about access to federal lands, and help understand the potential consequence of those decisions.

IMPLICATIONS FOR THE ROCKIES

The primary objective of this study was to develop a methodology that incorporates economic and environmental considerations into energy resource assessments. The methodology was developed with a focus on the Greater Green River Basin because of its overall high resource potential and its diverse range of deposit types and depths, which results in a large range in development and production costs. In doing so, we have highlighted some aspects of natural gas resources in the Greater Green River Basin that may not be directly evident from technically recoverable resource assessments. However, the value of this approach is expected to be even more evident when it has been applied to all the basins in the Rocky Mountains and eventually to all basins in the country. Just as a basinwide evaluation using a consistent methodology allows federal land managers to compare and prioritize areas within the Greater Green River Basin, a Rockies-wide evaluation will allow these managers to make the same type of comparisons and prioritizations among areas within different basins.

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GLOSSARY AND ABBREVIATIONS

Aquifer	A geologic unit that acts as an underground water reservoir
Aquifer recharge	The rate of infiltration of surface water into the soil and its percolation through the soil and unsaturated geologic material into the groundwater
ARI	Advanced Resources International
Associated gas	Natural gas produced from wells in which crude oil is the primary product
Bcf	Billion cubic feet
BLM	U.S. Bureau of Land Management (Department of Interior)
cf	Cubic feet
Coalbed methane	A type of natural gas resource in which the gas resides in coal deposits
Conventional	A type of natural gas resource in which deposits possess downdip water contacts and which can be extracted using traditional development practices
Depth to groundwater	Distance from the surface to the top of the initial groundwater aquifer
Drilling success rate	The ratio of successful holes to the total number of wells drilled
EIA	Energy Information Administration
EPCA	Energy Policy and Conservation Act
ERR	Economically recoverable resource
ESA	Endangered Species Act
FNAI	Florida Natural Areas Inventory

GIS	Geographic information system
Habitat	An area defined by certain ecological factors that generally supports certain associations of species
Human settlement	An area characterized by conversion of natural lands for general human use; does not include roads or agricultural use areas
Mcf	Thousand cubic feet
MMbbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
Natural gas liquids	The heavier components of natural gas that form liquids at atmospheric pressure and temperature
NEPA	National Environmental Policy Act
Nonassociated gas	Natural gas produced from wells in which gas is the primary product
Nonconventional	Resources contained in low permeability sandstone ("tight sandstone" or "tight gas"), shale, chalk, and coalbed deposits; also referred to as continuous deposits
NPC	National Petroleum Council
Play	A set of known or postulated oil or gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type
Proved reserves	Estimated quantities of a resource that are recoverable from known reservoirs under existing economic and operating conditions
psi	Pounds per square inch
Reserve appreciation	The resource expected to result from future extensions in existing pools in known producing reservoirs
Resource area	A spatial subdivision of a subplay; each subplay is divided into a producing, extension, and new field area
Resource category	A classification of resource distinguished by geological, engineering, or economic factors; primary categories are proved reserves, reserve appreciation, and undiscovered resources

Riparian habitat	An area that surrounds surface waters, with characteristic natural vegetation of such areas
Sensitive species	A plant or animal species that is identified by scientific criteria as warranting greater conservation effort or given special status under conservation law
Species richness	A measure of number of species groups expected to occur within a given habitat area
Stimulation	General term for a class of processes, including hydraulic fracturing and acidizing, used to increase porosity and increase gas or oil flow during production
Subplay	A specific portion of a play, as defined for this study
Surface slope	A ratio of vertical to horizontal change in distance above a level, horizontal axis
Surface water	Water that is apparent for significant periods of time at the earth's surface, both permanently (e.g., larger rivers and lakes) and seasonally (e.g., wetlands, ephemeral streams)
Tcf	Trillion cubic feet
Technically recoverable resource	The amount of energy resource that can potentially be recovered given current or anticipated future technology
Tight sandstone	Natural gas or oil reservoir rock with low permeability; see "nonconventional"
TRR	Technically recoverable resource
Undiscovered resources	Resources estimated to exist in new fields but which have yet to be discovered or confirmed
Upland habitat	An area beyond open water, wetland, and riparian areas, with characteristic natural vegetation of such areas
USGS	U.S. Geological Survey (Department of Interior)
Well recovery	The total amount of resource extracted from a well
Well spacing	The number of wells per unit area, usually expressed as wells per acre

Wellhead	The point at which the resource exits the ground; in the context of domestic price data, the generic term "wellhead" is used to reference the production site or lease property; in practice, the wellhead price is generally measured at the lease boundary and thus includes a fraction of the processing, compression, and gathering costs
WYGAP	Wyoming Gap Analysis Program
WYNDD	Wyoming Natural Diversity Database

Chapter One

INTRODUCTION

GAS RESOURCES AND PRODUCTION IN THE ROCKY MOUNTAINS

Natural gas demand in the United States has been increasing for the last 15 years and is expected to increase substantially in the next 20 years (Energy Information Administration, 2003; National Petroleum Council, 1999). Demand is projected to increase in all sectors, especially electricity generation (Figure 1.1). In fact, 80 percent of projected electricity generation capacity additions through 2025 is expected to be fueled by natural gas (Energy Information Administration, 2003). Meeting this increasing demand will require an accompanying increase in supply. Imports, over 95 percent of which come from Canada, at present account for approximately 15 percent of the natural gas supply in the United States (Energy Information Administration, 2001a). Although imports are projected to increase, the fraction of total gas demand met

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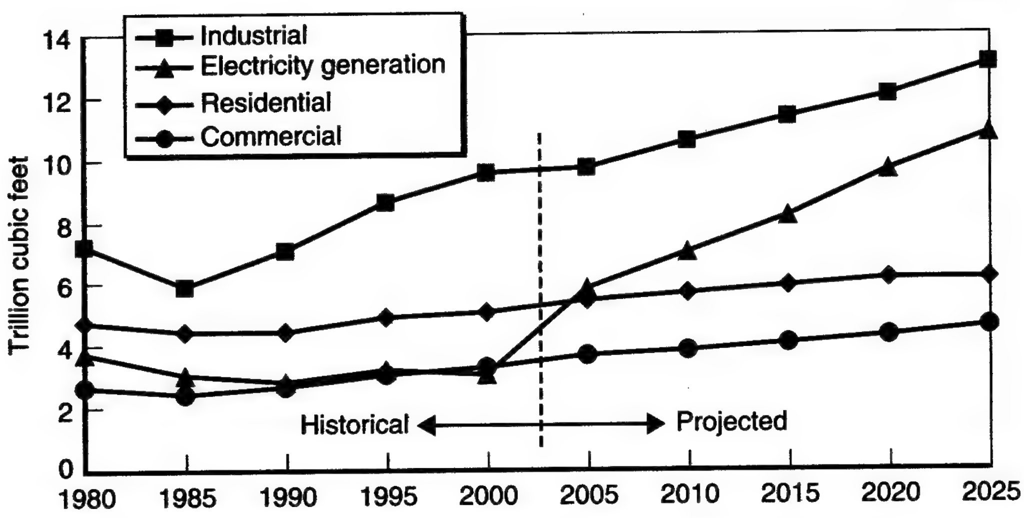

SOURCES: Historical data are from the Energy Information Administration (2001b). Projections are from the reference case of the Energy Information Administration (2003).

NOTE: Energy Information Administration reference case demand projections are made assuming no new legislation or regulation, such as that regarding CO_2 emissions or energy efficiency standards.

Figure 1.1—Historical and Projected Annual Natural Gas Demand

by imports is expected to reach only 22 percent by 2025 (Energy Information Administration, 2003). Thus, most of the increasing natural gas demand is expected to be met through increasing production in the United States.

The prospect of this production increase fuels ongoing efforts to both better assess our nation's natural gas resources and develop policies for developing those resources. Such efforts are drawing increasing attention to gas resources in the intermountain areas of the Rocky Mountains.

National resource assessments indicate that the Rocky Mountains are relatively rich in hydrocarbon resources, particularly natural gas (National Petroleum Council, 1999; U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995; Potential Gas Committee, 2001). These assessments indicate that the Rockies contain approximately 15 percent of the nation's proved reserves and technically recoverable (i.e., recoverable with current or anticipated future technology) natural gas supply (Figure 1.2). In 2001, production in this same region contributed approximately 9 percent of the natural gas produced in the United States. Thus, production in the region is lower than potential supply in terms of the fraction of the U.S. total.

In contrast, Texas, the Gulf Coast, and the Gulf of Mexico contain about 38 percent of the nation's future gas supplies, yet production in 2001 accounted for 62 percent of the nation's total (Figure 1.2). This suggests that production in the Rockies will grow as resources in the more established regions are depleted and production declines. Indeed, from 1997 through 2000, natural gas production in the Rockies increased by 15 percent whereas that in Texas, the Gulf Coast, and the Gulf of Mexico decreased by 5 percent (Energy Information Administration, 2001a). By most accounts, this trend of increasing production in the Intermountain West is expected to continue well into the future (National Petroleum Council, 1999; Energy Information Administration, 2003). Growing natural gas demand, particularly in California and the West, and the extent to which this demand may be met by increasing production in the Rockies, are important issues facing policymakers and the energy industry.

Accompanying the shift in production to the Rockies is a shift in land ownership and land use management responsibility. In the onshore parts of Texas, the Gulf Coast, and the Gulf of Mexico, which contain 60 percent of the reserves and technically recoverable resources in the entire region, 98 percent of the undiscovered gas underlies nonfederal land (Figure 1.3). Development decisions in this region involve primarily private landowners and states. In the Rockies, on the other hand, 60 percent of the undiscovered gas underlies federal land. Thus, an important implication of increasing natural gas production to the Rockies is that energy-related land use decisions are increasingly becoming the responsibility of federal land managers. Given the rapid increase in natural gas production occurring in the Rocky Mountains, demands upon federal land managers to open more lands for energy resource development will continue to mount. It is therefore important that these managers have access to any and all information that could potentially help inform the decisionmaking process.

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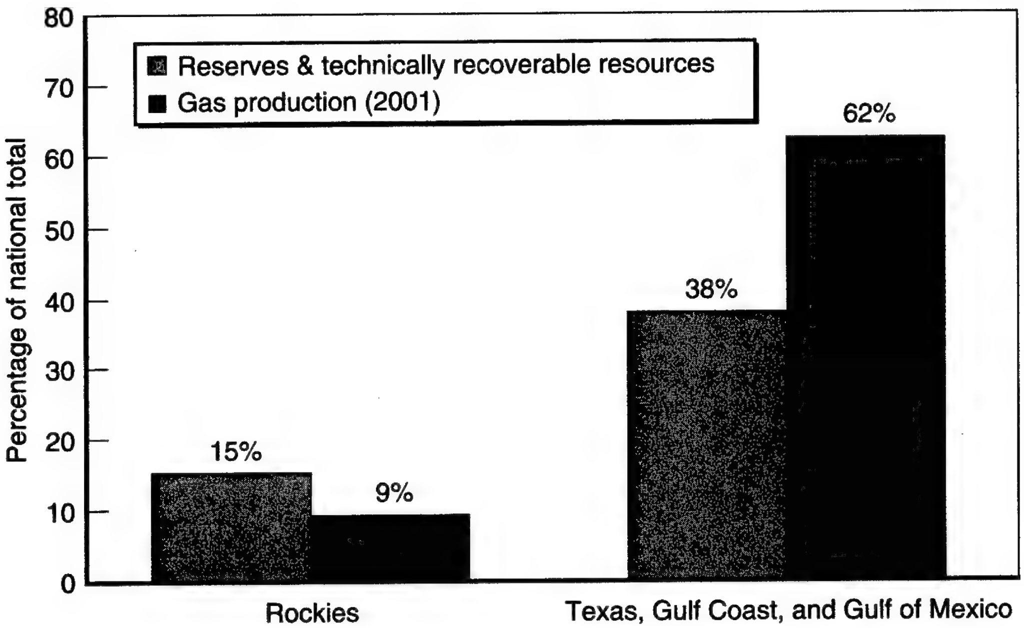


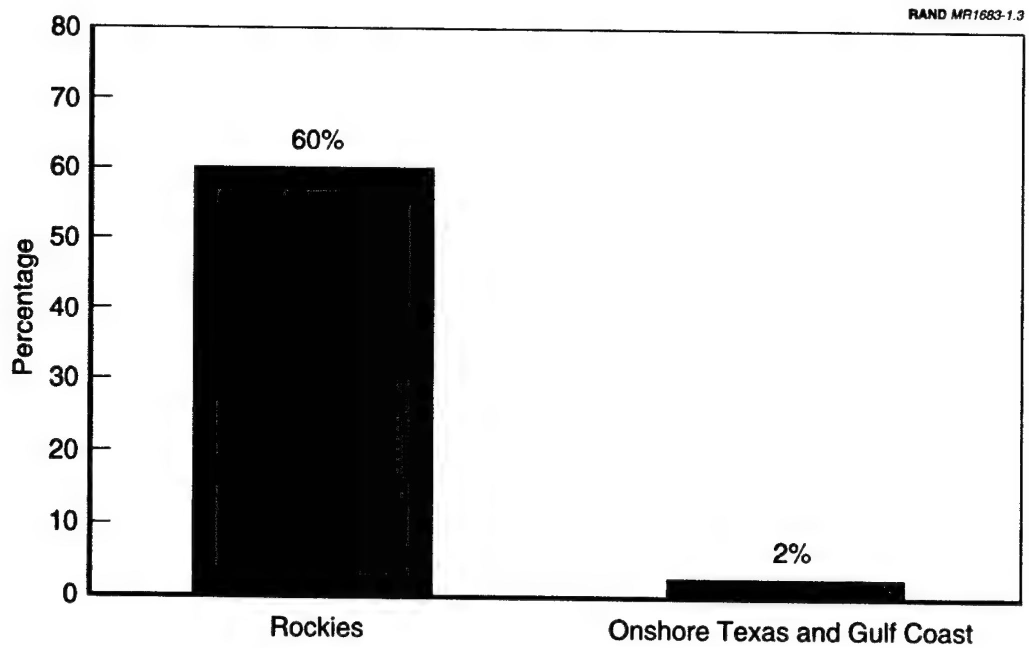
SOURCES: Data on reserves and production are from the Energy Information Administration (2002). Onshore data are provided by state and were allocated to U.S. Geological Survey (USGS) assessment regions as follows. Region four = MT + ND + SD + WY + CO/2. Regions five and six = NM/3 + TX + AR/3 + LA + AL/2 + MS/2 + FL. Technically recoverable resources include undiscovered conventional and nonconventional resources and reserve appreciation. Data on onshore and state offshore undiscovered resources are from the U.S. Geological Survey National Oil and Gas Resource Assessment Team (1995); onshore and state offshore reserve appreciation data are from Root et al. (1997); federal offshore undiscovered resources and reserve appreciation data are from the Minerals Management Service (2000).

NOTES: Rockies comprises USGS assessment region four; Texas, Gulf Coast, and Gulf of Mexico comprises USGS assessment region five and six plus the Gulf of Mexico. National total includes federal offshore.

Figure 1.2—Natural Gas Supply and Production in the Rockies, Texas, the Gulf Coast, and the Gulf of Mexico

RESOURCE ASSESSMENTS AND FEDERAL LAND MANAGEMENT

The federal government manages a vast array of natural resources in the nation, particularly in the western states. Much of this land management responsibility falls under the authority of the Bureau of Land Management (BLM) and the Forest Service. These and other agencies are responsible for deciding how federal lands are used, including the management of natural resources. This responsibility includes land use planning, leasing of federal land, and monitoring and evaluating land use activities. The Bureau of Land Management's land use planning process is governed primarily by the Federal Land Policy and Management Act as well as a number of



SOURCE: Data are from Gautier et al. (1998).

Figure 1.3—Percentage of Undiscovered Resources on Federal Land in the Rockies and in the Onshore and State Offshore Parts of Texas and the Gulf Coast

additional legal authorities reflecting environmental and resource management concerns. The process incorporates a variety of considerations and is guided by the general principles of multiple use and sustained yield (U.S. Bureau of Land Management, 2000).

Land use planning is a component of a comprehensive process that ultimately leads to the implementation of actions to carry out the plan. Although important for providing guidance for subsequent planning and approval activities, decisions made at the land use planning stage are strategic in nature and most actions that ultimately derive from these decisions are subject to more detailed examination in subsequent steps. For example, one outcome of land use planning may be the decision to open a particular area for gas or oil leasing; however, commencement of actual exploration and development activities is subject to additional permitting and approval. At the same time, however, in providing this strategic guidance, the land use plan clearly directs attention to specific areas for consideration for particular land uses. Land use planning thus establishes priorities for land use decisions.

In describing the land use planning process, the Federal Land Policy and Management Act refers to "resource value" as a consideration in assessing potential land uses. Resource is defined broadly to include the full range of potential commodities or uses that the land may provide. Resource values are determined in a variety of ways and in many cases are documented in the form of a quantitative or qualitative resource assessment. Such resource assessments play an important role in the land

use planning process. As described in the Bureau of Land Management's *Land Use Planning Manual*, "When making land use plan decisions, the BLM will consider information from all available sources, including scientific data gained from resource assessments, information regarding ecosystem protection and restoration needs, the reasonably foreseeable development of consumptive and nonconsumptive uses, and social and economic information" (U.S. Bureau of Land Management, 2000).

As a component of strategic land use planning, resource assessments are thus an important tool available to land managers in setting priorities for different land uses. Information regarding the potential value of a resource or activity helps land managers understand the possible implications of different land use decisions. Given the complex array of considerations involved in land use planning, the more information that land managers have available to them about different land use plan alternatives, the better able they will be to distinguish among plan strengths and weaknesses.

In the case of natural gas and oil, resource assessments historically focus on the amount of resource. The standard currency for gas and oil resources is the "technically recoverable" resource, which is the amount estimated to be recoverable given certain assumptions about current or anticipated future technical capabilities. In effect, the technically recoverable resource is an estimate of the amount that could conceivably be extracted. The amount of resource is a fundamental consideration, but additional attributes of energy resources affect the energy resource value of an area. A comprehensive assessment would include as much information about the resource as possible to help federal land managers distinguish among resources in different areas. Attributes of energy resources that influence their value include the following:

- How much resource might be recoverable,
- How much resource might be available at different costs, and
- How much resource is associated with lands having different values of key environmental measures.

In this report we describe a new approach for assessing natural gas and crude oil resources that incorporates these elements. We apply the approach to the Greater Green River Basin in southwestern Wyoming. Compared to current assessments, which focus primarily on the amount of resource, the more comprehensive assessment presented here expands the scope of energy resource assessments to include economic and environmental considerations.

Our primary objective is to help inform the land use planning process and improve federal land managers' ability to plan energy resource development. The potential benefits of our proposed resource assessment approach may reach beyond the formal federal land use planning process, however. It may also help inform national energy planning efforts; facilitate prioritization of permitting and approval processes within the context of existing land use plans; and help state planning agencies, utilities, gas and oil producers, and the associated investment community better plan future energy supplies and investment decisions. Before describing our approach in

more detail, we briefly outline some of the ways it may improve the utility of resource assessments and help inform policy decisions.

IMPROVING DECISIONMAKING WITH COMPREHENSIVE RESOURCE ASSESSMENTS

Federal Land Use Planning

As described above, the federal land use planning process provides strategic guidance for using federal lands taking numerous factors into consideration, including energy resource value. During this process, it would be helpful for land managers to have information on estimated production costs to help prioritize lands under consideration for energy resource exploration and development. Different areas with similar amounts of technically recoverable resource may have very different amounts of economically recoverable resource. Thus, estimates of production costs would provide useful information to help distinguish otherwise similar areas in terms of energy resource value.

Such an understanding would help land managers to more realistically consider energy resource development in the context of other land use considerations. For example, a choice to open land for gas or oil leasing might change the nature of the land, which could have significant implications for lands that currently have or are proposed for protected status. These decisions might be better informed if federal land managers could estimate the likelihood that the resource would be marketable within the next five to ten years. If the resource in a given area is expected to be too expensive, it might be prudent to focus attention on other areas where energy resources can be produced profitably.

Feedback from industry provides some guidance regarding the anticipated economics of different areas. However, a basin- or regionwide evaluation using a consistent and open methodology has the advantage of providing federal land managers with the best information for all areas, independent of proprietary information.

Our proposed approach is also intended to help inform the environmental protection aspects of federal land use planning. Environmental protection considerations are central to the land use planning process, which strives to balance the nation's need for domestic sources of minerals, food, timber, and fiber with the need to protect the quality of scientific, scenic, recreational, historical, ecological, and other environmental attributes (U.S. Bureau of Land Management, 2000). Because resource exploration and extraction may have adverse impacts on the environment, it may be important for federal land managers to know how much of the resource is on lands that are potentially vulnerable to these negative impacts. Our approach attempts to incorporate this information by providing a framework for identifying environmental attributes in the same spatial context as the energy resources. As with the cost considerations, such an environmental characterization could help inform the process of setting priorities for energy-related land use decisions. For example, managers might want to examine in more detail resource areas containing surface waters or wetlands because of the potential impacts of runoff or sedimentation; or,

they might need to consider more extensive mitigation efforts for processes or lands that may be associated with these potential impacts.

In including this environmental characterization, the intention is not to replace existing environmental impact analysis procedures, but rather to provide decisionmakers with an overview of how much resource is on lands that may require more detailed analysis before decisions are made or that might require increased mitigation efforts that could increase the costs of extraction.[1] This may also be important information for local communities who need to plan for future water needs, to plan for access to lands, and to understand the implications for ranchers, farmers, and others who might be affected by extraction activities.

Finally, the introduction of a systematic and transparent assessment methodology would provide a degree of consistency between separate land use plans. Traditional land use planning by federal land management agencies is conducted at the local (i.e., subfield office) level and can result in marked inconsistencies and discontinuities in planning consequences between adjacent areas. Such outcomes reflect a variety of factors, including differing assessment methodologies. Implementing our approach at a basin or regional scale may help minimize such problems.

National Energy Planning

For the purposes of energy planning and formulating national policies, it is important for the federal government to have a realistic view of how much gas and oil may be available as a function of cost in different areas. The relative merits of various options, such as increasing energy efficiency standards, investing in energy technologies, or pursuing expanded production in new areas such as Alaska or the Rockies, are difficult to compare without an understanding of the costs associated with each. Although it is common to discuss costs and savings associated with technology and efficiency initiatives, costs associated with production are much less clear.

In terms of meeting consumer demand, production costs have a strong influence on fuel choices as well as on the balance between imports and domestic production. Planning for future energy supplies thus depends strongly on estimates of energy resource production costs. The U.S. Department of Energy's Energy Information Administration (EIA) uses information like this in its forecasts, but the available data are uneven and incomplete. More accurate and detailed information would make its ability to forecast prices more reliable.

States, Utilities, and Producers

State planning agencies, utilities, gas and oil producers, and the associated investment community may also benefit from an improved understanding of gas and oil resource supplies, particularly estimates of the amount of resource expected to be

[1]As a requirement of the Energy Policy and Conservation Act of 2000, the federal government is involved in inventorying the natural gas resources in the Rocky Mountain region that are subject to various forms of access restrictions (see U.S. Departments of Interior, Agriculture, and Energy, 2003).

available as a function of price. As states become more dependent on natural gas for electricity generation, it is important that state planners who oversee their energy systems understand the resource potential. For example, it would be important to be able to estimate the price of gas if demand were to increase at a rapid rate. Price would be influenced by the amount of resource available at different production costs. California, for example, relies on natural gas supplied from a few western basins (Bernstein et al., 2002). For planning purposes, it would be useful to know how much gas is estimated to be available from those basins at different prices. Similarly, utilities, many of which are investing in gas-fired power plants with expectations of operating them for 30 or more years, could make better investment decisions with this type of information.

Economic Effects of Resource Extraction

A better assessment of the value of energy resources may also help stakeholders understand the positive and negative effects that resource extraction might have on the local, regional, and national economies. Increased extraction activities have positive economic elements but can sometimes replace economic activities that were previously on those lands. Positive economic benefits generally accrue locally, although property values and tourism can sometimes suffer. Estimates of the net economic effects of resource extraction are an important element in making land use decisions, in projecting revenues and jobs, and in other policy and forecasting issues. A realistic understanding of the economic effects at all scales depends on the amount of development and production activity that will actually occur. This is best estimated from the amount of resource that is expected to be profitable to produce.

GENERAL METHODOLOGY AND SCOPE

Our methodology for assessing natural gas and oil resources builds on existing technically recoverable resource assessments by incorporating economic and environmental considerations that further characterize energy resources. It is important to point out at the outset that the primary focus of this work is on the methodology used to make the assessment. Our results for the Greater Green River Basin reflect a reasonable range of assumptions regarding economic and environmental considerations. However, fine-tuning these assumptions to generate a precise resource estimate involves a number of stakeholder concerns and is beyond the scope of this work.

The general methodology is illustrated in Figure 1.4 and can be summarized in the following steps:

- Select a published technically recoverable resource estimate and allocate this resource among a defined set of individual analysis units,
- Evaluate the resource costs of each unit and generate cost-supply curves,
- Classify lands according to various environmental measures, and

- Evaluate, by means of geographic information system (GIS) overlays, the amount and distribution of resources that are economically recoverable at different costs and that underlie lands with differing values of environmental measures.

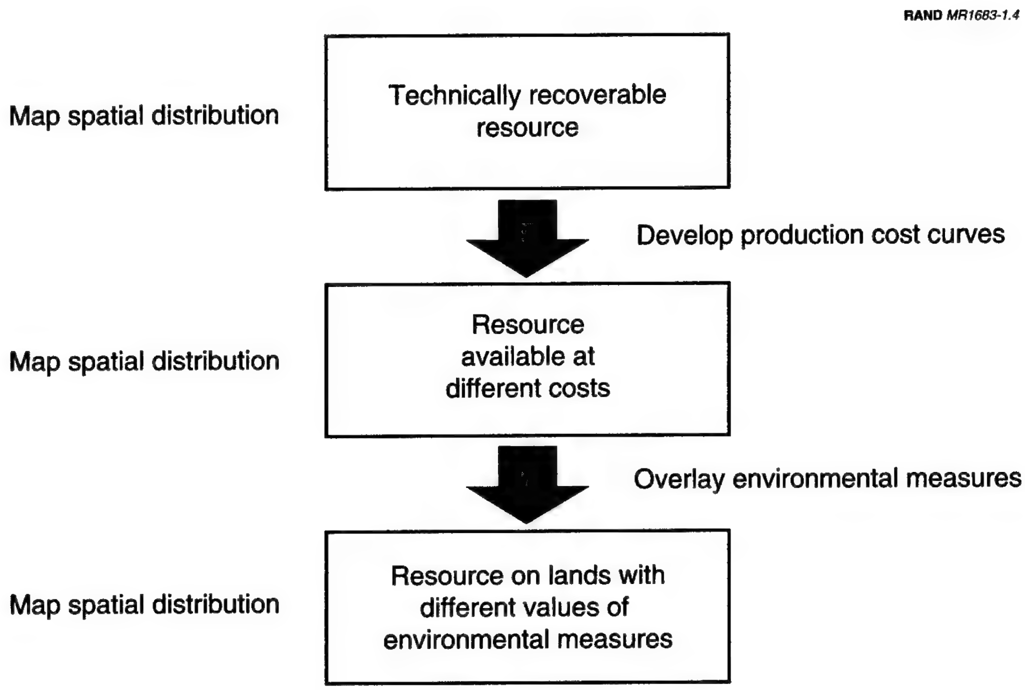


Figure 1.4—Summary of Approach

STUDY AREA

The methodology is being initially applied to the Greater Green River Basin because of the area's overall high resource potential and its diverse range of deposit types and depths, which results in a large range in development and production costs. The Greater Green River Basin is located primarily in southwestern Wyoming and includes a portion of northwestern Colorado and a small part of northeastern Utah. It comprises a number of individual structures including the LaBarge Platform, Moxa Arch, Rock Springs Uplift, Green River Basin, Great Divide Basin, Wamsutter Arch, Washakie Basin, Sandwash Basin, and others. Natural gas assessments for the Greater Green River Basin indicate that it may contain from 135 to 160 trillion cubic feet (Tcf), which represents approximately 50 percent of the remaining gas in the Rockies and 10 percent of the gas in the nation.

For our study area, we used U.S. Geological Survey (USGS) Province 37, Southwestern Wyoming (U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995; Figure 1.5). This area encompasses the entire Greater Green River Basin plus the Laramie and Shirley Basins to the east and extends northward through the Jackson Hole Basin to the Montana border on the west. Province 37 is

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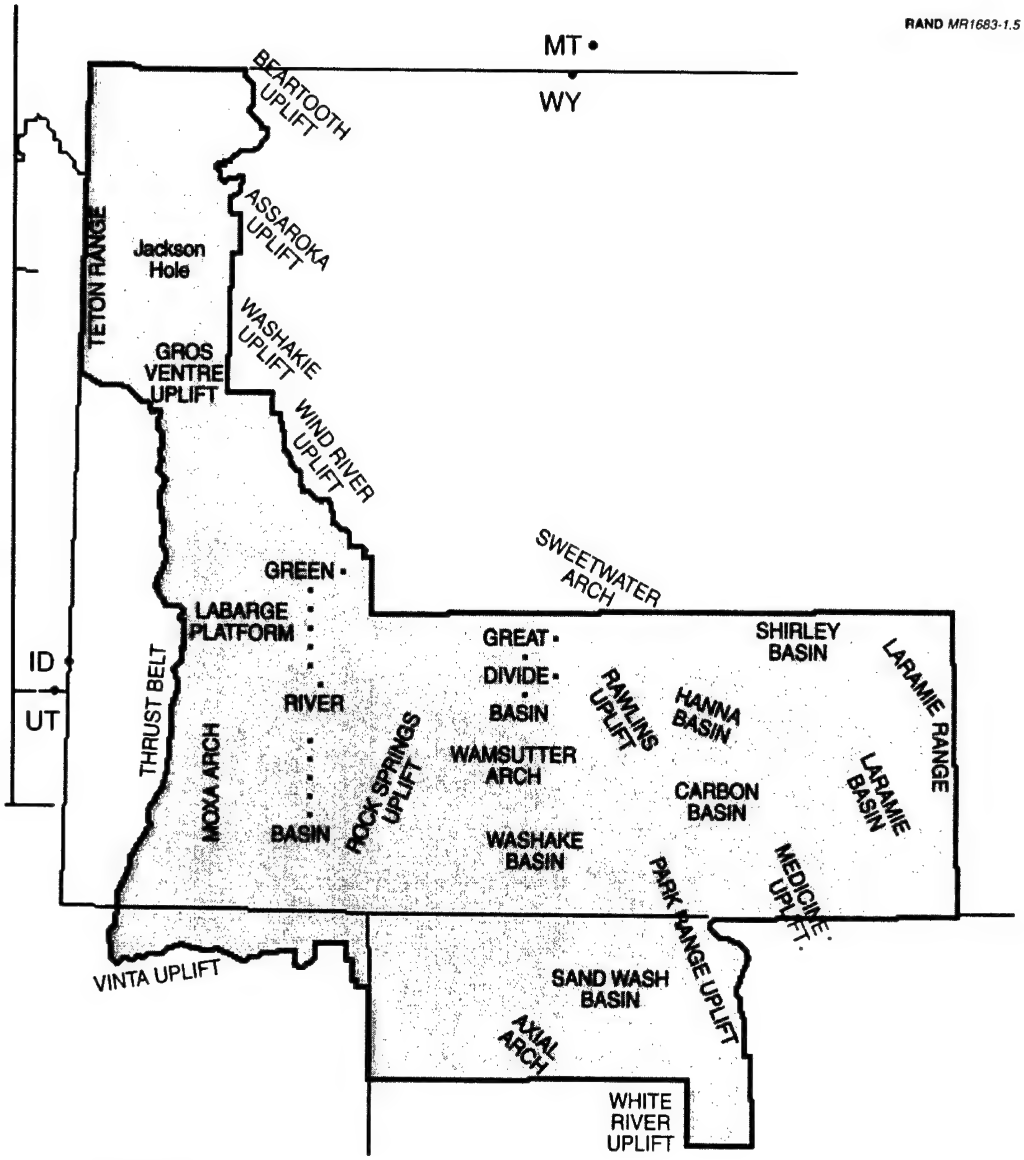

SOURCE: Beeman et al. (1996).

Figure 1.5—Study Area

larger than the Greater Green River Basin, although the vast majority of the gas and oil resources in the province lie within the Greater Green River Basin area. In this report, Greater Green River Basin refers to U.S. Geological Survey Province 37.

ORGANIZATION OF THIS REPORT

Chapter Two discusses the spatial analysis used to map the distribution of resources. The economic analysis methodology and results are presented in Chapter Three.

This is divided into wellhead costs[2] and infrastructure costs. The results are presented in terms of the spatial distribution of the amount of resource per unit area that is economically recoverable at different prices. Chapter Four discusses the environmental measures used in our analysis. These measures are associated with ecological and human resources that might be affected by gas or oil development. For each measure, we present the fraction of the gas resource underlying lands within the environmental study area having different values of the measure. The final chapter then presents our conclusions and the implications of our analysis for the Greater Green River Basin, the Rockies, and federal management of energy resources.

DATA AVAILABILITY AND DOCUMENTATION

We have endeavored to present our methodology in a transparent and reproducible way. Details of the spatial analysis, including data sources and descriptions, mapping procedures, and a description of the overlay analyses, are available on request. For the economic analysis, we have attempted to present a comprehensive discussion of the cost elements, data sources, and modeling procedure. This is supplemented with additional material available online.[3] Although all raw data are freely available, some details of the economic model are proprietary.

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[2]RAND obtained the services of Energy and Environmental Analysis, Inc., to conduct much of this analysis.

[3]Available at www.rand.org/publications/MR/MR1683.1.

ALLOCATION AND SPATIAL DISTRIBUTION OF RESOURCES

A primary component of our approach is the spatial distribution of resources throughout the study area. To map the spatial distribution of gas and oil resources, the quantities of resources from different estimates must be allocated to spatially defined units. The units used in this study are derived from the "plays" defined by the U.S. Geological Survey. Plays are sets of known or postulated oil or gas accumulations sharing similar geologic, geographic, and temporal properties.[1] To improve upon the spatial resolution provided by published assessments of technically recoverable resources, we divided the published plays into subplays, then further divided each subplay into three areas corresponding to the locations of different resource categories (proved reserves, reserve appreciation, and undiscovered resources). A key step in our methodology is defining these subplays and resource areas and allocating resources from published assessments to them.[2]

This chapter discusses this process. We begin by describing the subplays defined for this work. Because the allocation procedure differs for the different published assessments, we then present the technically recoverable resource assessments used in this study. The assessments differ in the level of spatial resolution (regional, basin, or play level) at which different resources are defined. The allocation step entails distributing the total quantities of resource from each assessment to the subplays. Finally, we describe the three resource areas within each subplay and how they were defined.

SUBPLAY DEFINITION

The U.S. Geological Survey play definitions have come into common usage in discussing gas and oil resources and therefore form the basis for the resource units in this report. The U.S. Geological Survey defined 20 plays in the Greater Green River Basin. To provide a greater level of detail, most of these plays were divided into subplays in this study. A total of 50 plays and subplays (collectively referred to as subplays in this report) were defined. Subplays in conventional plays were defined on

[1]See the glossary for definitions of terms used in this report.

[2]RAND obtained the services of Energy and Environmental Analysis, Inc., to conduct subplay definition and resource allocation. More technical detail is provided in supplementary material available online at www.rand.org/publications/MR/MR1683.1. Resource areas within subplays were defined by RAND.

the basis of formation or geologic age interval. Subplays in tight sandstone plays were defined by depth interval within the formation. This subdivision into subplays is useful in capturing formation- and depth-specific production characteristics, drilling depths, and associated costs. A complete list of the plays and subplays defined in this analysis is given in the appendix.

TECHNICALLY RECOVERABLE RESOURCE ASSESSMENTS

Government and industry organizations estimate amounts of technically recoverable natural gas and oil resources in the United States. We have used two commonly accepted technically recoverable resource assessments in our analysis: the U.S. Geological Survey (U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995) and the National Petroleum Council (NPC) (1999) assessments. Both assessments include associated and nonassociated and conventional and nonconventional natural gas. Crude oil is assessed explicitly by the U.S. Geological Survey. The National Petroleum Council assessment of the oil resource used in this study is consistent with the associated-dissolved gas resources of National Petroleum Council (1999). The methodologies and results of these assessments are discussed in LaTourrette et al. (2002).

The National Petroleum Council presents two assessments. One is made assuming present technology capabilities (the "current technology" scenario), and one assuming future technology capabilities (the "advanced technology" scenario). The main difference between these scenarios is in the estimated ultimate recovery per well for undiscovered resources (see National Petroleum Council, 1999, for more details).

RESOURCE ALLOCATION

The U.S. Geological Survey and National Petroleum Council technically recoverable resource assessments allocate the different categories of resources and deposit types variously at the regional, basin, or play level of detail. All of these resources had to be allocated at the subplay level for this study. Because of this step, the resource allocations derived in this study are referred to as "USGS-based" and "NPC-inspired" to distinguish them from those agencies' assessments. The current technology and advanced technology scenarios from the National Petroleum Council assessment were allocated in the same manner. Assessments are summarized in Table 2.1.

Proved Reserves

Our analysis includes proved reserves, which have been added to the technically recoverable resource assessments. The proved reserve volumes represent the EIA Form-23 reserves allocated to individual producing properties in the IHS database (IHS Energy Group, 2002). We assign a proven reserve volume to each gas completion based on an analysis of recent annual production from the specific completion. The assignment of reserves uses a reserve-to-production ratio applied to recent annual production. The summation of all of the assigned reserves for Wyoming gas

Table 2.1

Technically Recoverable Resource Assessments Used in This Study

Resource	Category	USGS-Based	NPC-Inspired Current Technology	NPC-Inspired Advanced Technology
Natural gas (Tcf)	Proved reserves	6.6	6.6	6.6
	Reserve appreciation	8.8	30	30
	Undiscovered	130	97	122
	Total	145	134	159
Total liquids (MMbbl)[a]	Proved reserves	148	148	148
	Reserve appreciation	756	290	290
	Undiscovered	1,583	1,052	1,338
	Total	2,443	1,491	1,777

NOTE: MMbbl = million barrels.

[a]Includes crude oil plus natural gas liquids.

completions, for example, equals the EIA year-end reserves for that state. Gas reserves are evaluated on both a wet and a dry gas basis.

Reserve Appreciation

Assessments of reserve appreciation were made at the regional level. These regional assessments were allocated to basins and then plays in proportion to the distribution of proved reserves. Because of differences in the methodologies used in making these assessments, the U.S. Geological Survey reserve appreciation was allocated to conventional plays only, whereas the National Petroleum Council reserve appreciation was allocated to conventional and tight sandstone plays.

Undiscovered Conventional Resources

The U.S. Geological Survey assessment of undiscovered conventional resources was made at the play level, so these resources needed only to be reallocated to subplays. This allocation was made based on the volumes of new field discoveries in the individual subplays made since 1974.

The National Petroleum Council assessment of conventional gas was made at the regional level and so allocating to the subplay level required additional steps. The resource was first allocated to the basin level using the Potential Gas Committee's basin-level allocation. It was then allocated to subplays based on the existing productivity of the subplay's developed areas, the U.S. Geological Survey play assessments, and recent exploration activity. A portion of the conventional resource potential in the National Petroleum Council assessment is expected to be in low permeability formations and was therefore allocated to the tight sandstone subplays.

Undiscovered Tight Sandstone Resources

The majority of gas resources in the Greater Green River Basin are contained in tight sandstone formations. Depending on the technically recoverable resource assessment, gas in tight sandstone plays accounts for 70–95 percent or more of the

undiscovered resources in the basin. Both the U.S. Geological Survey and the National Petroleum Council assessments of undiscovered tight sandstone resources were made at the play level. These resources were assigned to subplays based on historical well recoveries, drilling success rates, and well spacings.

Coalbed Methane Resources

Because coalbed methane is just beginning to be developed in the Greater Green River Basin, there is no adequate basis on which to subdivide the plays. This resource was therefore evaluated at the play level. The U.S. Geological Survey assessment was made at the play level and was used as is. The National Petroleum Council assessment and allocation were derived entirely from the U.S. Geological Survey values.

RESOURCE AREA DEFINITION

Three categories of resource were spatially distinguished in this analysis: proved reserves, reserve appreciation, and undiscovered resources. These resources were allocated to a producing area, an extension area, and a new field area within each subplay as shown in Table 2.2. Reserve appreciation potential, representing new production through the extension of existing fields, is assumed to occur both as infill within the producing area and as growth of an extension area surrounding the producing area. Producing, extension, and new field areas were defined in each subplay using GIS analysis, as described below.

Producing areas were defined based on the locations of successful wells. A well was assigned to a particular subplay if its position fell within the boundary of that subplay and its depth fell within the depth range for that subplay. Maps of successful wells in each subplay were created and contoured in terms of the number of wells per area. The producing area of a subplay was then defined as that area with a well density greater than 0.5 standard deviations above the mean density for the entire subplay. The producing area was not constrained to be a single contiguous area and in most cases consists of several discrete areas.[3] Well data used for this analysis were taken

Table 2.2

Spatial Assignment of Resource Categories

Resource Category	Resource Area
Proved reserves	Producing area
Reserve appreciation	50% to producing area 50% to extension area
Undiscovered resources	New field area

[3]The accuracy of the locations of producing areas derived with this method was qualitatively confirmed by a close agreement with published gas field locations.

from Beeman et al. (1996). This dataset consists of 1/4 mile grid cells, with each cell assigned a value of no well, dry hole, or successful well based on the status of any wells located within it. A value of successful indicates that there is at least one successful well in that cell. Because the surface projections of many subplays overlap, both location and depth of wells were used to assign wells to individual subplays.

Extension areas were defined as uniform buffers around the producing areas. The size of the extension area was estimated from the number of wells needed to extract half of the reserve appreciation resource (see Table 2.2) and the anticipated future well spacings. The number of wells was estimated from the amount of reserve appreciation resource and the estimated recovery per well. Well spacing was assumed to be 640 acres for conventional and 160 acres for tight sandstone and coalbed methane.[4]

The new field area was defined as the remainder of the subplay, and undiscovered resources were modeled as being homogeneously distributed throughout this new field area. This is a simplifying assumption made necessary because the location of undiscovered resources is, by definition, unknown. Thus, there is little justification for allocating undiscovered resources to particular areas within the new field area of a subplay. In reality, undiscovered resources will come online in discrete fields. This is well illustrated by the Jonah Field. The resource data used in this study predate the Jonah Field development and hence the reserves currently associated with that field are represented in our model as undiscovered resources distributed throughout the new field area of the Basin Margin Anticline play. The inability to predict locations of future fields is a limitation of any resource assessment. In our case, this shortcoming is tempered by dividing the basin into subplays and further subdividing resources among producing, extension, and new field areas within these subplays. As a result, the aerial extents of the new field areas are considerably smaller than the total play areas. In addition, subplays overlap each other extensively and the mapped distributions capture the spatial variability in resource concentration by summing the amounts in areas where subplays overlap.

The process described above was used to create maps of the producing, extension, and new field areas for each subplay. An example of such a map for Mesaverde subplay 2 is shown in Map 2.1 in the maps section. The map shows the study area and Mesaverde subplay 2, which is divided into producing, extension, and new field areas. Each of these areas is assigned a portion of the total technically recoverable resource base for the Greater Green River Basin through the allocation process described above. The sizes of the producing, extension, and new field area for each subplay and the gas and oil resources allocated to each subplay are shown in the appendix.

The total distribution of gas and oil resources and reserves in the Greater Green River Basin was generated by combining all of the individual subplay distributions and

[4]Note that determining the size of the extension area is the only point in our analysis that utilizes well spacings. This influences the spatial distribution only. A tighter well spacing would reduce the size of the extension area. Cost estimates in the next chapter are based on estimated recoveries per well and total resources, which determines the number of wells independently of well spacing assumptions.

summing the amounts in the overlapping areas. The resulting distribution of technically recoverable gas for the USGS-based scenario is illustrated in Map 2.2. Distributions for other scenarios are also shown in the maps section. Map 2.2 shows the distribution and amount, in billion cubic feet (Bcf) per square mile, of natural gas throughout the study area. Tight sandstone subplays and the Deep Basin play were defined by townships; hence, some parts of the map show a checkerboard type pattern. This map shows that the gas resource is concentrated in certain parts of the basin, including the LaBarge Platform and Moxa Arch on the west and the Great Divide and Washakie Basins in the central region (see Figure 1.5 for locations).

The appendix lists 50 individual subplays defined for the economic analysis. Subplays in the conventional plays are "stacked" and have identical surface projections. As a result, they are not spatially resolved in a surface map of the area. This leaves 33 spatially distinct subplays in this analysis. Dividing each subplay into producing, extension, and new field areas results in 99 entirely independent spatial analysis units. However, most of the subplays overlap several others.[5] The net result is that thousands of individual spatial analysis units are used to generate the map shown in Map 2.2.

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[5]The subplays reside at different depths and hence do not actually intersect. However, their surface projections overlap extensively.

Chapter Three

ECONOMIC ANALYSIS

The goal of our economic analysis was to estimate the amount of technically recoverable natural gas and oil in the Greater Green River Basin that can be extracted profitably at a given market price. The cost of extracting gas and oil in the Greater Green River Basin was estimated in two components: the wellhead cost and the infrastructure cost. The wellhead cost includes those costs associated with bringing the resource to the surface, as well as a number of additional steps such as compression, processing, water disposal, and initial gathering of resources from individual wells. The infrastructure cost refers to the costs associated with transporting the resource from the lease boundary to the interstate transmission pipelines. This is an important consideration in the Greater Green River Basin because of the remoteness and lack of existing infrastructure over parts of the region; substantial amounts of resources cannot be developed without constructing additional infrastructure. With production in the Rocky Mountain region increasing rapidly (Energy Information Administration, 2001a), infrastructure is expected to be an important part of future development.

The economic analysis consisted of constructing cost-supply relationships. To maximize the accuracy of the cost estimates, separate costs were estimated for multiple resource categories within each subplay. Cost estimates were further refined by modeling resource depletion through time.[1]

WELLHEAD COSTS

Wellhead costs per volume of resource were estimated separately for each resource subcategory within each subplay (e.g., undiscovered nonassociated gas in Mesaverde subplay 2). The distinction between resource categories is made because reserve appreciation applies to reserves from existing fields, for which many of the exploration costs have already been incurred. The finding and development costs for resources from reserve appreciation are thus lower than for undiscovered resources. No costs were estimated for proved reserves; production costs were assumed to be zero for all proved reserves.

[1]RAND obtained the services of Energy and Environmental Analysis, Inc., to estimate the wellhead costs. A full technical description of this analysis is available aonline at www.rand.org/publications/MR/MR1683.1. Infrastructure costs were estimated by RAND.

Costs for each of these analysis units were further broken down into ten separate increments reflecting the effect of resource depletion on well recovery and drilling success rates. As a basin is developed over time, well recovery declines because the better areas are developed first. Drilling success rates also decline through time as exploration targets become smaller and more difficult to find.[2] This breakdown structure resulted in over 1,200 individual analysis units for which separate costs were calculated.[3]

Both nonassociated gas (gas from gas wells) and associated gas (gas from oil wells) are included in the analysis. Natural gas liquids from gas wells were also included and amounts and costs are combined with the results for oil and collectively referred to as "total liquids."

Cost estimates were constructed from estimates of a number of individual cost elements using a discounted cash flow model. The model calculates the amount of resource that can be produced in the Greater Green River Basin for a given cost, which is equivalent to the selling price at which the resource can be produced profitably.

Cost Elements

Important cost elements are discussed very briefly below.[4]

Drilling. Drilling costs increase with depth and differ for gas wells, oil wells, and dry holes. For gas wells, separate costs were further distinguished for coalbed methane and sour (corrosive) gas.

Stimulation. Most deposits in the Greater Green River Basin require stimulation (typically hydraulic fracturing) to extract the resource. Costs were estimated using historical data on the number of stimulation zones per well in each subplay.

Equipment. Equipment includes such items as flowlines, separators, dehydrators, pumps, compressors, and storage tanks. Costs were estimated from the results from the Rocky Mountain region of a survey conducted by the Energy Information Administration. Costs vary with well depth as well as with the characteristics of the resource.

Operations and Maintenance. Operating costs include such items as labor, overhead, fuel, chemicals, and surface and subsurface maintenance. Costs were estimated from the Energy Information Administration survey.

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[2]See supplementary material at www.rand.org/publications/MR/MR1683.1 for more discussion.

[3]Individual costs are calculated for each of 50 subplays, two resource categories (reserve appreciation and undiscovered resources), two resource subcategories (associated and nonassociated gas in the case of gas or oil and natural gas liquids in the case of total liquids), and ten increments, giving a total of 2,000 cost analysis units. Many of these have zero values (e.g., there is no associated gas in coalbed methane deposits), leaving 1,221–1,391 calculated cost analysis units, depending on the scenario.

[4]Details on cost elements, including data sources, are given in the supplementary material available at www.rand.org/publications/MR/MR1683.1.

Processing. Some of the gas in the basin (primarily in the Deep Basin play) contains substantial quantities of nonhydrocarbon components. Interstate pipelines specify maximum impurity levels for gas entering the pipelines, and gas with higher levels (often referred to as low quality or low Btu gas) must undergo purification or blending before delivery. Processing costs are derived from the gas composition in each subplay.

Gas Compression. Gas entering interstate pipelines must be supplied at a pressure of approximately 1,000 pounds per square inch (psi). Coalbed methane is produced at very low pressures (~100 psi) and so must be compressed. Compression costs are based on the compression ratio, amount of gas to be compressed, and fuel requirements and also include capital and operation and maintenance costs. Noncoalbed gas is assumed to be produced at 600–700 psi in the early part of a well's life and hence compression costs are negligible (<5¢ per thousand cubic feet (Mcf) and were ignored.

Water Disposal. Coalbeds have high porosities and are water saturated; this water must be removed before the methane can be desorbed from the coal. Coalbed methane production is therefore accompanied by large volumes of formation water. Although coalbed methane production is just beginning in the Greater Green River Basin, formation water will probably have to be reinjected into the subsurface because of its high salinity. Subsurface reinjection is more costly than the surface discharge currently used in the Powder River Basin. Preliminary estimates of water production rates and disposal costs were taken from environmental impact statements and industry press releases.

Geological, Geophysical, and Lease. Per well geological and geophysical costs were estimated by distributing national totals for geologic and geophysical investment as reported to the American Petroleum Institute across all wells drilled. Lease costs were based on actual lease costs (bonus cost) for federal and state land in the Rocky Mountain region in 2000–2001.

Taxes, Royalties, and Return on Investment. The model assumes a 6 percent Wyoming state severance tax and a 7 percent county ad valorem tax for the Greater Green River Basin area. Federal and state income tax is assumed to total 30 percent. The model assumes federal royalties of 12.5 percent. The required after-tax real rate of return in the model is 6.3 percent. This value is based on a capitalization ratio of 60 percent debt and 40 percent equity for which debt and equity have nominal rates of return of 7 percent and 15 percent, respectively, after-tax rates of 4.9 percent and 15 percent, respectively, and real after-tax rates of 2.3 percent and 12.2 percent, respectively. This ratio results in a nominal rate of 10.2 percent, an after-tax rate of 8.9 percent, and a real after-tax rate of 6.3 percent.

The values of many of these cost elements, most notably drilling, are influenced by well depth, which varies from 2,200–21,500 feet throughout the basin. Two other important characteristics of the subplays—drilling success rate and total recovery per well—also influence costs. Drilling success rates in the model range from 12 percent to 95 percent and vary by subplay, resource category, and depletion increment. For unsuccessful wells, drilling costs are somewhat lower and many of the other cost el-

ements decrease or vanish. Total recovery per well affects the total number of wells that must be drilled to extract the resource from the subplay.

Examples of subplay characteristics and values for cost elements for four subplays are shown in Table 3.1. Cloverly-Frontier Tight and Deep Basin are very deep plays and have among the highest costs in the basin. Deep Basin also requires substantial costs for gas processing. The Tertiary section of the Moxa Arch is a relatively shallow conventional subplay with relatively low costs, and Almond Coalbed illustrates the compression and water disposal costs. Overall, costs tend to be dominated by drilling and stimulation. Although Deep Basin has very large processing costs, it is one of only two subplays that require extensive processing, and processing costs are not substantial costs for the basin overall. For coalbed methane wells, compression and water disposal costs are also significant.

Table 3.1

Examples of Wellhead Cost Elements for First Depletion Increment of Undiscovered Gas from NPC-Inspired Advanced Technology Scenario

Well Characteristic	Unit	Cloverly-Frontier Tight Subplay 5	Deep Basin	Moxa Arch Upper Cretaceous	Almond Coalbed
Average depth	Feet	21,500	18,500	4,695	2,245
Drilling success rate	Percent	83	76	84	85
Total recovery per well	MMcf	1,396	13,167	2,379	607
Cost element					
Drilling	$1,000/well (successful)	6,867	8,863	351	190
Stimulation		657		153	31
Equipment		45	113	34	69
Geological and geophysical		31	31	23	21
Lease		61	61	47	43
Operations and maintenance	$1,000/year	32	64	22	31
Processing	$/MMBtu (marketable gas)		7.71		0.08
Compression					0.18
Water disposal					0.45
Infrastructure		0.12	0.06	0.07	0.13
Net gas cost	$/MMBtu (marketable gas)	16.05	11.83	0.97	4.48

NOTE: Drilling success rate and total recovery per well decrease with increasing depletion increment, so values shown for these parameters are maximums for the plays listed.

Discounted Cashflow Model

The economic analysis of gas and oil resources was based on a discounted cash flow model developed by Energy and Environmental Analysis, Inc. Model inputs include a subplay-allocated resource assessment and assumptions for drilling and completion costs, stimulation costs, geological and lease costs, per well gas and oil recoveries, production parameters, drilling success rates, taxes, rate of return criteria, and expected Btu content and gas composition. Production from each well was characterized by a total recovery volume, Btu content of the dry hydrocarbon gas, condensate yield (for gas wells), gas yield (for oil wells), and average annual takes. A

deliverability forecast in the form of a hyperbolic decline curve was used to model production as a function of time for up to a 50 year life of the well. In addition, as discussed above, each subplay was modeled in ten depletion increments in which the total recovery per well and drilling success rate decreased with each increment.[5]

In addition to using different well recoveries, the NPC-inspired current technology and advanced technology scenarios differ in two other respects. In the advanced technology scenario, drilling costs were reduced by 5 percent and drilling success rates were increased by factors of 1.023 and 1.07 for reserve appreciation and undiscovered resources, respectively.[6] These factors contribute to the differences in cost between these scenarios.

The output of the model is the resource cost, which is the selling price required to compensate producers for their investments, operating costs, taxes, royalties, and cost of capital. Resource costs are calculated in dollars per MMBtu of dry marketable gas.[7] The amount of resource in the Greater Green River Basin available at a given price was obtained by summing the resource amounts in the individual cost analysis units that have a resource cost less than or equal to that price.

INFRASTRUCTURE COSTS

Assumptions

The infrastructure costs presented in this report represent a first-order estimate and neglect several factors that may influence the actual cost. In general, our assumptions likely minimize the cost estimate. For example, we include in the infrastructure costs only the cost of building pipelines to transport resources from the wellhead to the interstate transmission pipeline. Other potentially important costs, such as additional interstate pipeline capacity, operations and maintenance, capital costs for increasing processing capacity, roads, or housing, are not included. We further assume that future infrastructure costs will apply to undiscovered resources only; proved reserves and reserve appreciation are assumed to be transported through the existing pipeline infrastructure. We estimate infrastructure costs for natural gas only.

We modeled the cost of the pipeline infrastructure necessary to bring resources from the wellhead to the interstate pipeline in terms of linear distance. The pipeline is modeled as a three-stage tree structure (see Figure 3.1). The first stage comprises the flowlines from individual wells. Note that the cost of the first stage of flowlines is included in the wellhead costs and is not included here. Flowlines assumed in this estimate are one inch in diameter and one mile long. Twenty-five flowlines connect to a small gathering line, assumed to be four inches in diameter and three miles long.

[5]Cashflow model details are given in the supplementary material, available at www.rand.org/publications/MR/MR1683.1, and in Vidas et al. (1993).

[6]In all cases, drilling success rates were capped at 95 percent and 85 percent for reserve appreciation and undiscovered resources, respectively.

[7]The average heating value of dry gas in the Greater Green River Basin is 1,080 Btu per cubic foot (cf), so the cost per MMBtu is 8 percent higher than the cost per Mcf ($\$/\text{MMBtu} = 1.08 \times \$/\text{Mcf}$).

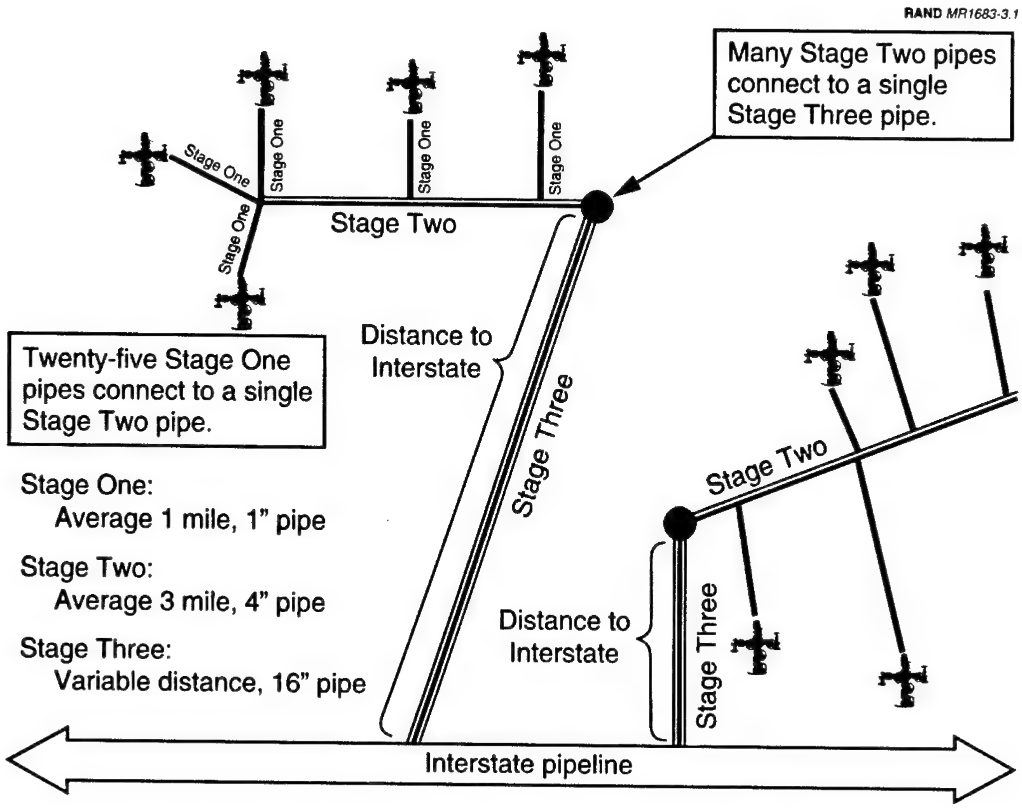

Figure 3.1—Pipeline Tree Structure Used to Model Infrastructure Costs

Three thousand small gathering lines connect to 200 16-inch diameter large gathering lines which lead, in turn, to the interstate lines.

Pipeline Capacity Requirement

The pipeline capacity required is determined by the anticipated gas production rate. Our model assumes that proved reserves and reserve appreciation will be transported to the interstate pipelines through the existing pipeline infrastructure and that new pipeline is required for undiscovered resources. That is, any remaining capacity of the existing pipeline network (excluding interstate transmission lines) is required to accommodate proved reserves and future reserve appreciation. Although this is deemed a reasonable assumption for the regional scope of this analysis, it should be substantiated through further analysis.

The total amount of undiscovered technically recoverable gas in the basin is approximately 116,000 Bcf (average of the three assessments; see Table 2.1). Using estimates for the total recovery per well, the wellhead cost model requires approximately 75,000 new field gas wells to produce the undiscovered gas.[8] For production over 50

[8]For a productive area of 25,000 square miles, this gives a well spacing of 213 acres.

years, this equates to an average production rate over time and space of approximately 85 Mcf per day per well. In reality, a well's maximum production rate may be many times its lifetime average value, increasing the overall pipeline capacity requirement relative to the average. Conversely, not all wells in the basin will be producing simultaneously, reducing overall pipeline capacity requirement relative to the average. If these two effects are of comparable magnitude (e.g., if a well's maximum production rate is four times its average and one-quarter of the basin is producing at any one time), then the average production rate may be a good approximation to the required pipeline capacity. Assuming this requirement, the pipeline was modeled to accommodate this flow at 35 percent capacity utilization.

Costs

Cost per inch in diameter per mile in length of gathering system amounts to approximately \$10,000 to \$15,000 for the small gathering lines in the second stage and \$40,000 to \$100,000 for the large gathering lines in the third stage. The former estimate was developed from conversations with industry, and the latter from estimates of larger pipelines described by the Department of Energy's Office of Fossil Energy. The range in the latter reflects the lower marginal cost per mile of longer pipelines compared to shorter pipelines. These costs are averages and do not explicitly incorporate costs of routing through mountainous terrain and other factors that may increase the costs, siting, or building of the lines. A payback period of 50 years is used for the pipelines with a real after-tax discount rate of 7 percent.

The requirement for the first two pipeline stages is the same regardless of where the wells are located. The cost thus varies with the distance that the third stage lines must run to reach the interstate pipeline. The cost data, tree structure, and capacity requirement were then combined to generate a cost-distance relationship that was used to estimate infrastructure costs.[9] Costs range from about \$0.05 per Mcf at five miles to about \$0.35 per Mcf at 100 miles.

Interstate transmission pipelines were defined as gas pipelines with a diameter of 25 inches or more. The locations of pipelines are shown in Map 2.2 and all subsequent gas maps in the maps section.[10] Per volume infrastructure costs were estimated for individual subplays, based on distance to interstate pipelines. Using GIS, the fraction of area within five mile increments of the interstate lines was calculated for each subplay. Resource volume was estimated from this area fraction and the total undiscovered resource allocated to that subplay. This assumes that the gas volume per unit area is homogeneous over the subplay. Infrastructure costs for each distance increment were calculated with the cost-distance relationship determined above. Finally, a weighted average infrastructure cost for each subplay was calculated from the infrastructure cost for each increment weighted by the fraction of undiscovered resource in that increment. These weighted average infrastructure

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[9]This cost per Mcf for infrastructure as a function of distance from interstate pipelines can be approximated as follows: Cost (\$/Mcf) = $4 \times 10^{-7} d^3 - 7 \times 10^{-5} d^2 + 0.0061 d + 0.0213$, where d = distance in miles.

[10]The pipeline network map was purchased from PennWell MAPSearch, Durango, CO.

costs range from \$0.07/Mcf to \$0.29/Mcf. Costs for four subplays are shown in Table 3.1.

The total cost for each subplay was calculated by adding the wellhead and infrastructure costs for each undiscovered resource analysis unit.

ECONOMIC RESULTS

The basinwide results of our economic analysis are summarized in the form of cost-supply curves in Figures 3.2 and 3.3. Each curve shows the amount of technically recoverable resource (TRR) as a function of the resource cost, which is equivalent to the selling price at which that amount can be profitably extracted and transported to the interstate transmission pipeline. An inset in each figure shows the same data over an expanded cost range. The curves are constructed from over 1,200 analysis points, each representing the cost associated with an individual increment of gas or oil.

For gas, the amount available at any cost is greatest for the NPC-inspired advanced technology scenario, least for the NPC-inspired current technology scenario, and intermediate for the USGS-based scenario. For total liquids, the USGS-based scenario yields the greatest amounts above \$12 per barrel, and the NPC-inspired advanced technology scenario gives the greatest amounts at costs lower than this. The amount

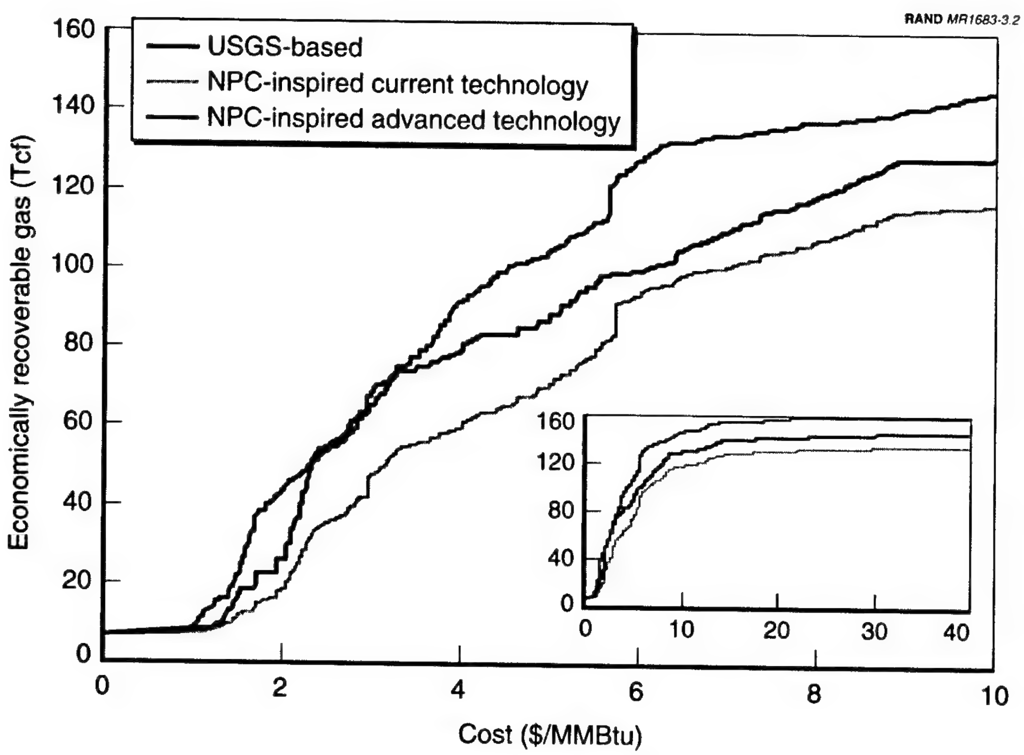

Figure 3.2—Gas Cost-Supply Curves for the Three Assessment Scenarios

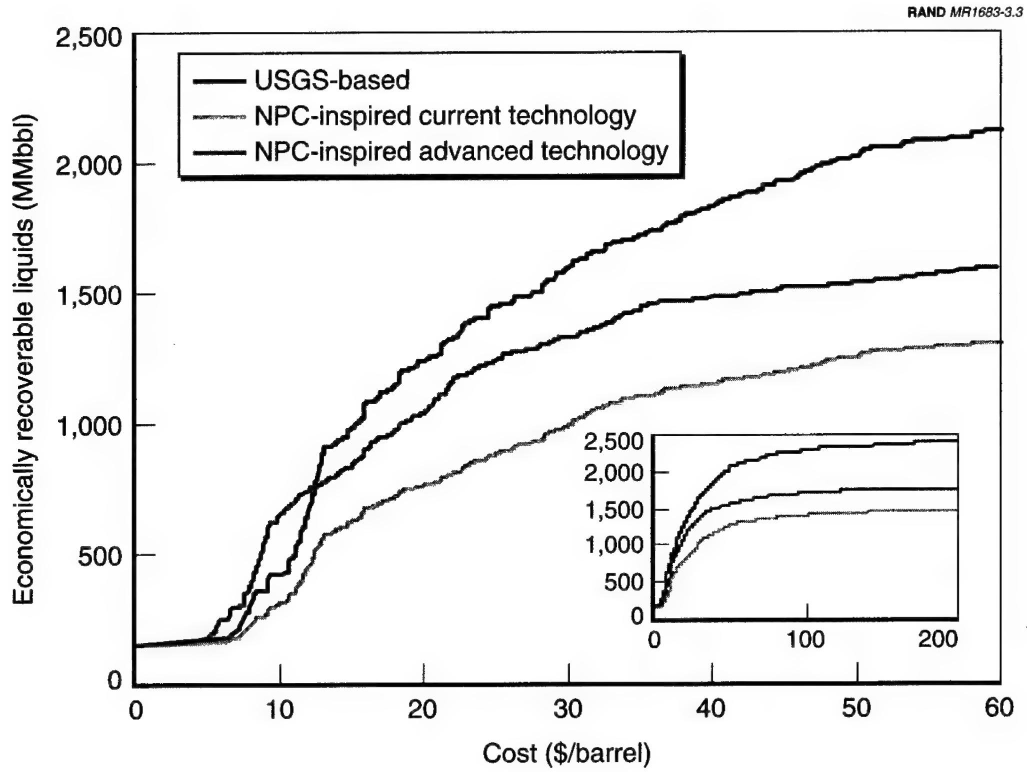

Figure 3.3—Total Liquids (Crude Oil Plus Natural Gas Liquids) Cost-Supply Curves for the Three Assessment Scenarios

of economically recoverable gas at several costs is shown in Figure 3.4 and tabulated in Table 3.2.

The results presented in Figures 3.2–3.4 and Table 3.2 represent the economic costs required to produce natural gas and oil in the Greater Green River Basin. The relationships generated in this model allow one to estimate how much resource can be profitably produced at a given price. The average wellhead price in the state of Wyoming from 1996 through 2000 was $2.42 per Mcf, or approximately $2.61 per MMBtu (Energy Information Administration, 2001a). At a price of $3 per MMBtu, from 35 to 45 percent of the technically recoverable gas in the Greater Green River Basin may be economically recoverable, depending on the scenario. Approximately 90 percent of the gas is economic at $10 per MMBtu. These estimates of economically recoverable resources are substantially greater than prior estimates for the Greater Green River Basin (Attanasi, 1998).[11]

An example of the spatial distribution of the economically recoverable gas is shown in Map 3.1 in the maps section. This map shows the location and amount of gas that is economically recoverable at a price of $3 per MMBtu. This map is analogous to

[11]Note that such comparisons are problematic because of large differences in data and methods.

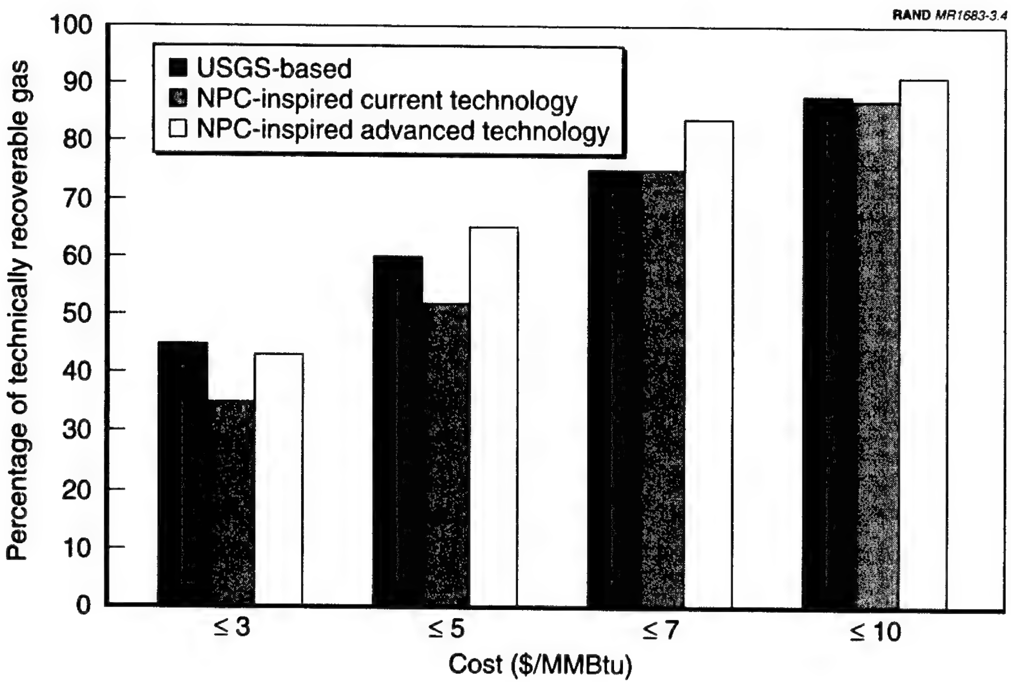

Figure 3.4—Economically Recoverable Gas at Different Costs for the Three Assessment Scenarios

Table 3.2

Economically Recoverable Gas at Different Costs

		Cost ($/MMBtu)			
Scenario	Resource Category	≤3	≤5	≤7	≤10
USGS-based	Reserve appreciation	2.4	5.9	7.2	8.4
	Undiscovered	56	74	95	113
	Total[a]	65	87	109	128
	% of TRR	45%	60%	75%	88%
NPC-inspired current technology	Reserve appreciation	9.1	14	25	27
	Undiscovered	31	49	69	83
	Total[a]	47	70	100	116
	% of TRR	35%	52%	75%	87%
NPC-inspired advanced technology	Reserve appreciation	9.9	14	25	27
	Undiscovered	51	83	102	111
	Total[a]	68	104	134	145
	% of TRR	43%	65%	84%	91%

NOTES: Quantities are given in trillion cubic feet. TRR includes proved reserves.
[a]Total includes 100 percent of proved reserves.

Map 2.2 but instead of showing the total technically recoverable resource, it showsthe amount of the technically recoverable resource that can be produced at costs of up to $3 per MMBtu as determined from the cost-supply relationships. Additional maps for other scenarios and other prices are presented in the maps section.

Maps 2.2 and 3.1 show broadly similar patterns, indicating that the overall spatial distributions of economically and technically recoverable resources are generally similar. However, the amount of gas per area at any location is lower in Map 3.1, reflecting the lower amount of economically recoverable relative to technically recoverable gas. In addition, the difference between the amount of technically and economically recoverable resources varies from place to place. This is apparent in several areas, including much of the Washakie Basin, the northeastern portion of the Great Divide Basin, and the northwest trending area just south of the Wind River Uplift (see Figure 1.5 for locations).

The high resolution of both the cost and spatial analyses provides a useful tool for federal land managers that can help them identify areas where resources are likely to be profitable to produce at different prices. In so doing, it provides a more comprehensive picture of the values of the different subregions of natural gas and oil resources throughout the Greater Green River Basin. As an example of how it might be used, the analysis indicates that natural gas in much of the Washakie Basin, while abundant (Map 2.2), is expected to be relatively more costly to produce than that in many other areas (Map 3.1). This information could help guide a decision in permitting energy development elsewhere in the basin.

SENSITIVITY OF RESULTS TO UNCERTAINTIES

There are several sources of uncertainty in our cost estimates. To begin with, there is a fundamental uncertainty in the estimates of technically recoverable resources used as a basis for the economic analysis. Energy resource assessments attempt to estimate amounts of unexplored and undiscovered natural gas and oil and are consequently highly uncertain. Technically recoverable resource assessments are conducted periodically and estimates have historically increased from one assessment to the next (e.g., Fisher, 2002). As such, they are often referred to as being "dynamic." The economically recoverable resource assessment presented here is based on these technically recoverable resource estimates and thus is also subject to change with time. It is therefore important to keep in mind that the results presented here reflect current knowledge and need to be revised periodically to account for increased exploration, improved technologies, and any other factors that may modify our estimates.

An additional uncertainty is the effect of the way in which resources were allocated (i) to subplays, (ii) to resource categories and areas within subplays, and (iii) within resource areas. The first two allocation steps affect total costs and all three influence the distribution of economically recoverable resources. Varying the amount of resources among the different subplays will influence total costs because different subplays have different characteristics that affect costs. Allocation of resources to resource areas within subplays is governed by the allocation of resources to resource categories (see Table 2.2), which also have different cost characteristics. Distribution of resources within resource areas does not affect costs because costs are estimated from the number of wells required. The number of wells is determined from the amount of resource and recovery per well and does not depend on the location of

those wells. Thus, modeling undiscovered resources as being homogeneously distributed throughout the new field areas of the subplays has no influence on costs or on the amount of economically recoverable resource. It does, however, affect the spatial distribution, which is an important component of our approach. To a first-order approximation, this issue has been addressed in this study by dividing the published U.S. Geological Survey plays into subplays. Further refinement would involve detailed geologic modeling that is beyond the scope of this initial analysis. In general, the influence of alternative resource allocation schemes on total costs and the distribution of economically recoverable resources is an important topic for further analysis.

The economic analysis itself incorporates a large number of variables and assumptions. Drilling costs, for example, fluctuate in response to gas prices and drilling rig availability: Higher prices lead to greater rig demand, which drives up drilling costs (e.g., Gas Research Institute, 1999). The drilling costs used in this analysis are based on data from a single year and thus may not capture the full range of costs over longer timescales. A sensitivity analysis was conducted to estimate the effect of changes in drilling costs and a number of other variables. The effect of several variables on the amount of gas available as a function of cost is illustrated in Figure 3.5. In addition to the variables shown, halving stimulation costs, water disposal costs, and inflation has negligible effects and these cases are not shown. Most of these variables have relatively small effects, particularly at costs less than $4/MMBtu.

Compared to most of the variables shown in Figure 3.5, the effect on costs of the different initial economic scenarios is greater. This can be seen by comparing Figures 3.2 and 3.5. The primary differences among the scenarios are the starting amount of technically recoverable resource and the modeled recoveries per well. Thus, the overall uncertainty in the economic modeling is dominated primarily by uncertainties in these two factors. The propagation of these differences in the resource distribution can be assessed by comparing Map 3.1 to maps for the other scenarios included in the maps section.

The notable exception is selectability. Selectability refers to the ability of producers to preferentially select the most economical well locations ("sweet spots") first. Selectability is represented in the cost model by the rate of decline of well recoveries over the ten depletion increments. The model uses a different decline rate for reserve appreciation and undiscovered reserves in each of conventional, tight sandstone, low Btu, and coalbed methane deposits. These decline rates were estimated from a number of sources, including the National Petroleum Council natural gas studies.[12]

Well recoveries within a tight sandstone subplay can vary greatly depending on factors such as natural fractures and depositional trends. Industry has shown some ability to target better areas first, and this is reflected in the decline rates used in the model. However, future technology could greatly improve industry's ability to target these better areas. This would have the effect of making more gas available at lower cost.

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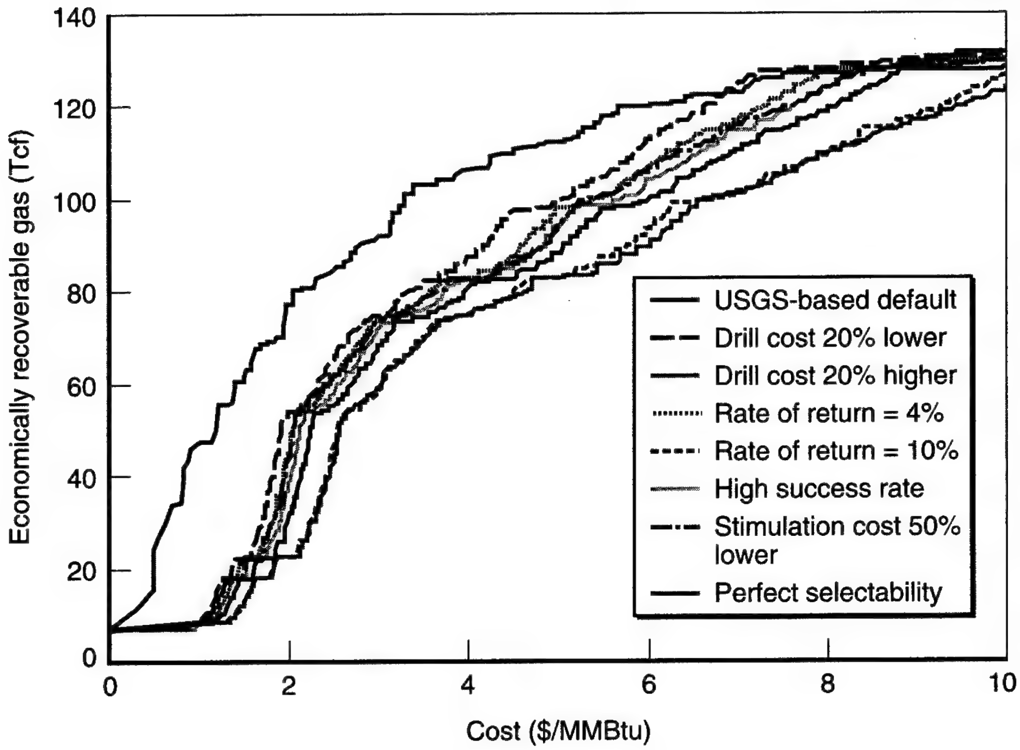
[12]See supplementary material at www.rand.org/publications/MR/MR1683.1 for more discussion.

RAND MR1683-3.5



NOTE: For the "high success rate" case, drilling success rates were fixed at 85 percent for undiscovered resources and 95 percent for reserve appreciation (compared to 10–85 percent in the default scenario).

Figure 3.5—Effect of Model Variables on the Amount of Economically Recoverable Gas

Petroleum Council natural gas studies, tight sandstone well recovery statistics were evaluated to determine the variability in well recoveries in groupings of 10 percent of the wells. Perfect selectability is modeled here by setting the average well recovery in the initial depletion increment equal to the best 10 percent of the total recovery distribution, recovery in the second increment equal to the next 10 percent of the distribution, and so on. The results for perfect selectability of undiscovered resources in tight sandstone subplays are shown in Figure 3.5. Note that perfect selectability is a theoretical case that is unlikely to ever be realized. It is shown to illustrate the effect of resource targeting on overall costs. Note also that substantial additional costs may be incurred by producers in improving selectability. Such costs have not been accounted for in our model.

Perfect selectability changes the shape of the supply curve so that much more of the gas is recoverable at lower costs. Note that the average cost does not change, nor does the total amount of gas produced. Rather, by the ability to target the best locations first, more of the gas is made economical at lower costs. The finding that resource costs are more sensitive to selectability than other factors has important im-

plications for understanding gas and oil costs. The results indicate that substantial cost savings may be realized from improvements in exploration technologies.

A final area of uncertainty to contend with is the appropriate spatial resolution for interpreting the economic results. A first-order estimate can be derived using the dimensions of the economic analysis units as a guide. The 33 spatially distinct subplays distributed over a total study area of 25,000 square miles gives an average economically resolvable cell length of 28 miles. This calculation is conservative in that it neglects the distinction between resource areas within individual subplays, which improves the resolution still further. However, this estimate is complicated by the fact that the various production parameters and cost estimates used in the model reflect averages over large numbers of wells. Applying these data to a small number of wells in one area may not be straightforward, as the variance in factors such as drilling success rate or recovery per well increases as the number of wells considered decreases. Thus, although the average costs will not change, costs at any given area may be higher or lower. As a target for further study it would be useful to quantify this uncertainty.

Chapter Four

ENVIRONMENTAL MEASURES

Another important consideration in assessing the value of energy resources is the potential environmental risk associated with gas and oil development activities. In this chapter, we describe a method for characterizing energy resources according to selected environmental measures of the lands they occupy. Such a characterization provides an important starting point for assessing potential environmental risks. Different lands may be more or less susceptible to environmental impacts, and evaluating the risk of such impacts requires an understanding of the proposed activities and a characterization of the environmental attributes of those lands. Our approach links this environmental characterization to the energy resources in an effort to include it as a component of the resource assessment. We apply this method to the natural gas resources in the Greater Green River Basin.

As outlined in a previous report (LaTourrette et al., 2002), a useful way to consider the potential environmental risks of gas and oil development is in terms of characteristics of the lands in which they are located. Our environmental analysis therefore focuses on identifying relevant environmental measures of the lands in which natural gas may be present and calculating the locations and amounts of potential gas resources within areas having differing values of these measures. Different values of environmental measures reflect different levels of potential environmental risk, which may, in turn, translate to a need for further environmental analysis, greater mitigation requirements, or actual environmental impacts. For example, producing gas in certain areas indicated as having higher species density may pose greater risk to biodiversity or require greater mitigation efforts.

This analysis is intended to be part of a broader set of information sources to be used by decisionmakers in assessing gas and oil resources. We do not intend to define particular areas where drilling may be inappropriate, nor do we suggest that gas or oil project–related impacts in these areas would definitely occur. Rather, our intent is to provide a framework for treating environmental characteristics as an attribute of energy resources and to provide decisionmakers with a way to evaluate these attributes when assessing energy resources for strategic planning purposes.

METHODOLOGY

Issues and Measures

Consideration of environmental issues and selection of environmental measures were based on their relevance to the potential impacts of natural gas and oil exploration and development in general. In defining general categories of issues to address, we consulted three general sources: scoping reports of environmental impact statements in which various stakeholder groups identified a number of potentially relevant issues for gas and oil extraction projects in Wyoming (e.g., U.S. Bureau of Land Management and U.S. Department of Agriculture, 2000), U.S. Bureau of Land Management and Forest Service access restrictions (e.g., Potential Gas Committee, 2001, Table 16), and experts with knowledge of environmental issues in the study area. Further discussion and review of the literature regarding potential measures of environmental impacts from gas and oil development are given in LaTourrette et al. (2002). From these sources, three general categories of environmental issues emerged:

- Ecosystem quality,
- Human environmental considerations, and
- Water quality.

Our selection of measures was guided not only by their relevance to potential impacts but also by our desire to minimize the use of complex or controversial model-dependent measures (e.g., hydrologic transport rates). Our selection was further constrained by the availability of data. The suite of environmental measures we present is not an exhaustive list of relevant environmental indicators but is intended to provide meaningful insight into some potential environmental risks across the majority of the study area. Conversely, some of the measures (aquifer recharge rate and depth to groundwater) are less relevant to the Greater Green River Basin than other areas, as production methods in the Greater Green River Basin thus far have had relatively low impacts on groundwater quality. We selected seven environmental measures for this analysis:

- Terrestrial vertebrate species richness,
- Proximity to sensitive species observed locations,
- Surface water and riparian habitat zones,
- Proximity to human settlements,
- Surface slope,
- Aquifer recharge rate, and
- Depth to groundwater.

In addition to these measures, we also examined the distribution of different categories of lease restrictions for natural gas development on federal land.

Overlay Analysis

To evaluate the amount of resource having different values of the environmental measures, the measure values were grouped or "binned" at various cutoff points. Ideally, bins would be chosen on the basis of empirical relationships between gas and oil development activities and potential environmental impacts. However, this requires knowledge of a causal relationship between measures and impacts which we do not possess. Therefore, in this initial analysis, we define the bins primarily from statistical criteria. In some cases scientific or regulatory criteria were also used. Using statistically derived bins does provide a relative sense of environmental concern for this specific area and in so doing provides useful guidance. However, they say little about actual environmental risk and in that sense the environmental measures need to be developed further.

For each environmental measure, we evaluated the amount of potential natural gas resource underlying lands having different bin values. This was accomplished using GIS overlay analysis—a process by which separate spatial distributions are combined to generate a new distribution representing their intersection. Note that in most cases environmental data were available for Wyoming only. Maps of environmental measures and overlay analyses are therefore confined to the portion of the study area in Wyoming. Overlay results presented in this chapter are normalized to totals for Wyoming only. Separate overlays were calculated for the technically recoverable gas and the economically recoverable gas at several costs. In each case, the overlay resulted in an amount of gas underlying land possessing a particular value of an environmental measure. The environmental measures were defined such that every point in the study area is assigned one value for a given measure. Thus, there is no overlap between areas having different values and there is no area where no value is assigned. As a result, the sum of gas from each overlay is the same and equal to the total gas with no overlay. Overlays were calculated for gas distributions from the USGS-based scenario only.

ECOSYSTEM QUALITY

The development of gas and oil resources has the potential to disrupt complex associations of vegetation and wildlife in the study area, potentially warranting greater care or mitigation in certain areas to maintain an acceptable level of ecological function.

Ecological Setting

The Wyoming Basin (Omernik, 1987) defines the largest ecoregion within our study area. This semiarid region is characterized by relatively low rainfall (less than 16 inches annually throughout the entire basin, and less than seven inches annually in some areas in Wyoming) and irregular basin terrain that includes isolated mountains and plateaus with local relief generally greater than 30 meters. Vegetation includes widely scattered shrubs and grasses dominated by sagebrush, saltbush, and various short-stem grasses. Some uplands include juniper and pine. A number of wet val-

leys, riparian areas, and wetlands also occur across the Wyoming Basin, each containing more water-dependent plant species. At higher elevations, the study area includes open woodland, coniferous forest, and alpine meadows. This variety of landform and vegetation across the study area defines a number of interrelated habitats for a variety of species, including fish, fowl, and big game species, as well as important macroinvertebrates and microbes found in soil and streams.[1]

Measures of Ecological Function

According to the National Research Council (2000) the level of ecological functioning can be indicated by a number of measures including species diversity, soil condition, and nutrient runoff. In a subsequent section (Water Quality), we will consider the potential for increased nutrient runoff and disruption of soils as they may relate to gas and oil development. In this section, we present three ecological measures that correlate with species diversity and species density:

- Terrestrial vertebrate species richness,
- Proximity to sensitive species observed locations, and
- Surface water and riparian habitat zones.

These measures are intended to indicate areas of different levels of general ecological function and do not differentiate between the particular characteristics or needs of individual species.

Terrestrial Vertebrate Species Richness. Species richness is an important indicator of available ecological resources of an area. We consider richness of higher trophic-level species (i.e., vertebrates), which may correspond with areas of greater ecological complexity. Degradation of an area may have an adverse effect on species richness, indicating a loss of ecological resources or a decrease in ecological function in that area.

In our analysis, we use data compiled by the Wyoming Gap Analysis Program (WYGAP; Wyoming Gap Analysis, 1996a), which is part of the larger National Gap Analysis Program under the Biological Resources Division of the U.S. Geological Survey. These data describe predicted distributions of 445 terrestrial vertebrate species, represented by 116 species of mammals, 291 birds, 26 reptiles, and 12 amphibians in Wyoming. These data reflect overall species richness in that they comprise numbers of species, not individuals. All species are treated equally, regardless of numbers of individuals within each species. Note also that richness describes the number of species groups within a given modeled habitat area; these functional areas may vary in size. Areas of higher richness values correlate with higher species diversity in those areas.

WYGAP generates species richness data in a GIS modeling process using more than 700,000 point observations, species-habitat association rules, and habitat condi-

[1]See Mac et al. (1998) for an overview of ecosystems and species within the Rocky Mountain area.

tions.[2] The median value of the species richness distribution is 119 species per area, with areas of highest species richness nearer water and at higher elevations. To characterize the variability in species richness across the basin, we selected bins separated at the first quartile and median richness values as follows:

- Less than 98 species per area,
- 98 to 119 species per area, and
- Greater than 119 species per area.

The spatial distribution of species richness according to these bins is shown in Map 4.1 in the maps section.

Results of the overlay analysis are shown in Table 4.1 and Figure 4.1. The tables in this chapter list the results in terms of both the percentage of economically recoverable resource and the percentage of technically recoverable resource at each cost. The percentage of economically recoverable resource reflects the distribution of the economically recoverable resource among the different measure values; these values sum to 100 for each measure. This is illustrated by the relative proportion of the different shadings within each column in Figure 4.1. The percentage of technically recoverable resource gives the percentage of technically recoverable gas that is both recoverable at the listed cost and has the specified value of the environmental measure. This is illustrated by the absolute amount of each shading within each column in Figure 4.1. The sums in these columns give the economically recoverable fraction of the technically recoverable gas and are consistent with the values in Table 3.2 (slight differences occur because the results in Table 4.1 are for the Wyoming portion of the study area only).

These results indicate that areas containing more than 119 species groups, or greater than the median value for the study area, contain approximately 18 percent of the total technically recoverable resource. Areas potentially supporting 98–119 species and less than 98 species account for 46 and 36 percent of the technically recoverable resource, respectively (right-most column in Table 4.1). When considering the economically recoverable resource, these percentages decrease as the modeled cost decreases. For example, 7 percent of the technically recoverable resource is both economical to produce at or below $3/MMBtu *and* is on lands with >119 species/area.

When cast in terms of the percentage of economically recoverable resource, the percentages of gas having different values of vertebrate species richness are nearly independent of cost. For example, regardless of the cost considered, the fraction of economically recoverable gas on land with >119 species per area ranges only from 17 to 18 percent (Table 4.1). The similarity of the relative distributions at different costs is apparent from the similar proportions of different shadings in each column in

[2]Range limits of each species were delineated within a grid of 436 hexagons (635 square kilometers each) and refined by consideration of additional information describing land cover, elevation, riparian model, and review by more than 60 local experts. Comparisons of species predicted to occur in eight field sites to species lists maintained for the sites indicated an overall accuracy of 79.5 percent. These data are meant to be used at 1:100,000 scale or smaller (Wyoming Gap Analysis, 1996b).

Table 4.1

Natural Gas at Different Costs from USGS-Based Scenario Having Different Values of Ecosystem Quality Measures

	Cost ($/MMBtu)						
	≤3		≤5		≤10		
Environmental Measure	% of ERR	% of TRR	% of ERR	% of TRR	% of ERR	% of TRR	% of TRR
Terrestrial vertebrate species richness							
>119 species/area	17	7	17	10	18	16	18
98–119 species/area	43	18	43	25	46	40	46
<98 species/area	41	18	40	23	36	32	36
Sum	100	43	100	57	100	87	100
Proximity to sensitive species observed locations							
<2,000 meters	14	6	14	8	14	12	14
≥2,000 meters	85	37	86	49	86	75	86
Sum	100	43	100	57	100	87	100
<6,500 meters	65	28	65	37	65	57	64
≥6,500 meters	35	15	35	20	35	31	36
Sum	100	43	100	57	100	87	100
Surface water and riparian habitat zones							
Open water, wetland, riparian	9	4	10	6	11	10	11
Upland	91	39	90	51	89	77	89
Sum	100	43	100	57	100	87	100

NOTES: % of ERR = [economically recoverable gas at listed price with specified value of environmental measure]/[economically recoverable gas at listed price]. % of TRR = [economically recoverable gas at listed price with specified value of environmental measure]/[technically recoverable gas]. Sums may differ slightly from totals because of rounding.

Figure 4.1. This finding holds true for all of the environmental measures considered in this study. Note that this results from the particular distributions of resources and environmental measures in this basin and cannot necessarily be generalized to other areas.

Proximity to Sensitive Species Observed Locations. Rarer species often have greater conservation interest than more common species. Their loss is associated with reduced biodiversity in local areas as well as increased risk for regional or global endangerment. These species often have very particular habitat requirements and are very sensitive to their loss. Thus, degradation of areas potentially constituting critical habitat for sensitive species may have implications for biological diversity and ecosystem health.

The locations of species or associations that scientists have identified as sensitive or are protected by conservation laws[3] are recorded in the Wyoming Natural Diversity Database (WYNDD). The WYNDD includes observations of terrestrial and aquatic

[3]Sensitive species can be defined under a number of federal, state, and local regulations. Two measures of sensitivity we consider are threatened or endangered listing under the federal Endangered Species Act (ESA) and imperiled or critically imperiled status under the Natural Heritage ranking system. The Heritage ranking system was developed, and rankings are continually updated as biological information is acquired, by NatureServe and its Natural Heritage Program members. In this system, element occurrences (field observations of species, subspecies, or ecological communities) are assigned ranks on global (G), national (N), and subnational (S) scales. These ranks range from critically imperiled (1) to widespread, abundant, and secure (5). In accordance with the protocol used by Florida Natural Areas Inventory (FNAI) (2001), we consider sensitive species with Heritage ranks 1 or 2 on G, N, or S scales in our analysis.

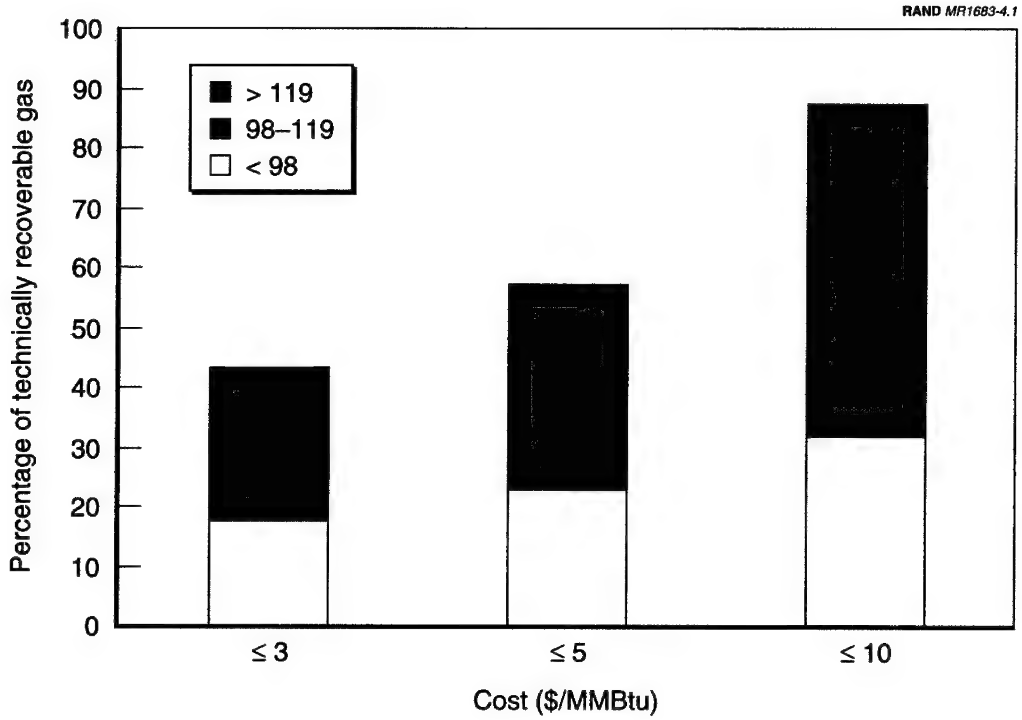


Figure 4.1—Terrestrial Vertebrate Species Richness Overlay Results

vertebrates (i.e., mammals, birds, reptiles, amphibians, and fish), invertebrates, plant species, as well as vegetation associations. A spatial precision attribute is also included with each observation in the WYNDD.[4] Note that the WYNDD includes point observations of species over a 50 year time frame and that the vast majority of WYNDD data represent results of spring and summer field surveys. The WYNDD point data by themselves do not define habitat ranges and in particular may not capture winter species patterns.

Our overlay analysis requires environmental measures with spatial dimensions of area; to derive spatial areas from sensitive species observation points, it was necessary to define areas that correlate reasonably to species ranges. We used a buffering approach based in part on a method defined in the Florida Natural Areas Inventory (2001). FNAI defines buffers around observation points based on the biology of the individual species. These buffers generally range from approximately 2,000 to 6,500 meters at minutes precision. According to the FNAI protocol, buffers are subsequently refined by expert review of suitability of habitat enclosed by the buffer. Unsuitable habitat is discounted from the modeled areas.

[4]For this measure, we consider only points with minutes precision (approximately one mile) or seconds precision (a few hundred meters), consistent with the protocol used in Florida Natural Areas Inventory (2001).

For our analysis, we calculated overlays for buffers of 2,000 meters and 6,500 meters. Buffering aggregated sensitive species data occurrences by these values gives us a range of values that likely encloses actual sensitive habitat areas for many species occurring within our study area.[5] The smaller buffer may underestimate the range of some vertebrates, whereas the larger buffer may overestimate the range of certain plants, vegetation associations, and invertebrates. In our screening-level analysis, we do not qualify buffered areas on the basis of habitat conditions, which may contribute to an overestimate of the range of species in some buffered areas.

Note that the environmental study area includes a small number of species of large mammals, raptors, and migratory birds, with ranges on the order of ten to 1,000 kilometers. We do not consider wide-ranging mammals and birds in our analysis, in part because buffering points with appropriate radii would cover the entire environmental study area (thus not introduce variability useful for decisionmakers) and also because most of these points are reported with general precision, which, according to FNAI protocol, are not included. We note that the most frequented habitats by wide-ranging species within the environmental study area occur at higher elevations beyond the Wyoming Basin. For our analysis, we consider areas within and beyond 2,000 and 6,500 meter buffers, according to the following bins:

- Within 2,000 meters of sensitive species observed locations,
- Beyond 2,000 meters of sensitive species observed locations,
- Within 6,500 meters of sensitive species observed locations, and
- Beyond 6,500 meters of sensitive species observed locations.

The spatial distribution of sensitive vertebrate species distribution according to these bins is shown in Map 4.2 in the maps section.

As shown in Table 4.1, our results indicate that potential habitat for sensitive species may account for between approximately 14 and 65 percent of the total technically recoverable resource or the economically recoverable resource at any cost. Results of overlays for different gas costs are shown in Figure 4.2.

Surface Water and Riparian Habitat Zones. Water is an important factor for the survival of many plant and animal species in the study area. Development in close proximity to areas that are hydraulically connected may have relatively greater chance of affecting surface water quality. Species diversity and density are strongly associated with surface water habitats. According to the Wyoming Gap Analysis (1996b), 83 percent of terrestrial vertebrate species have an association with aquatic

[5]No single buffer is appropriate for all species considered. Certain species, e.g., plants and invertebrates, may occur over distances of approximately 200–500 meters from their observed point. Adding error at minutes precision (approximately 1,600 meters), an appropriate buffer radius for these species is approximately 2,000 meters. Similarly, many vertebrates occur over a range of up to 5,000 meters, suggesting an appropriate buffer radius of approximately 6,500 meters.

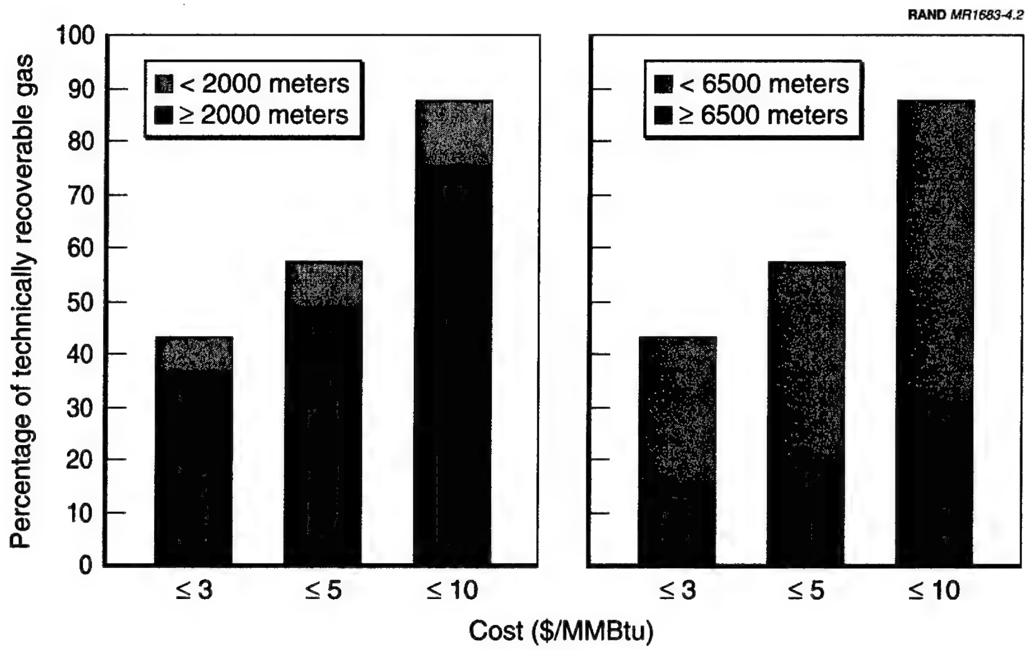


Figure 4.2—Proximity to Sensitive Species Observed Locations Overlay Results

and riparian habitats. In our own separate analysis, we found a strong association of WYNDD sensitive species observed locations with these areas.[6]

To capture this important ecological zone, we have defined a measure that distinguishes surface water and riparian habitat zones from uplands:

- Surface water, wetlands, and riparian areas,[7] and
- Uplands.

These bins are differentiated by distance from surface water and are distinguished by differences in species density. Riparian areas generally correlate with higher species density relative to uplands. In addressing habitat zones, this measure complements the species diversity and sensitive species observations measures as an indicator of

[6]Sensitive species observed locations from WYNDD (critically imperiled, endangered, or threatened vertebrates) were associated with the nearest stream, lake, or reservoir, taken from digital line graph data from the U.S. Geological Survey (Wyoming Gap Analysis, 1996c) and a distance was measured. A histogram of these distances shows a clear maximum at zero distance and a smooth decrease in number of species with distance from water. Mean distance from water increased in order for fish, amphibians, mammals, birds, and reptiles as one might expect. The median distance for all species was less than 300 meters, and the third quartile score was approximately 850 meters. Mean distance for fish observations was approximately 150 meters, which provides an estimate of the positional uncertainty in the data.

[7]Surface waters and wetlands data were taken from U.S. Fish and Wildlife Service (1997). Riparian areas were defined by a buffer around streams. We model riparian areas using stream buffer distances specified by WYGAP, which range from 40 to 210 meters, depending on the stream order.

ecological function.[8] Note that the quality of riparian habitat can vary considerably, and differentiating areas of higher and lower quality would improve this measure. However, collecting data in riparian habitat quality requires detailed field surveys and such data are not available for much of our study area. We therefore include all riparian areas in our measure. The spatial distribution of these zones is shown in Map 4.3 in the maps section.

Results in Table 4.1 show that surface water, wetland, and riparian areas account for approximately 10 percent of the resource recoverable at any cost, and upland areas account for approximately 90 percent of the economically recoverable resource. Overlay results for gas distributions at different economic costs are shown in Figure 4.3.

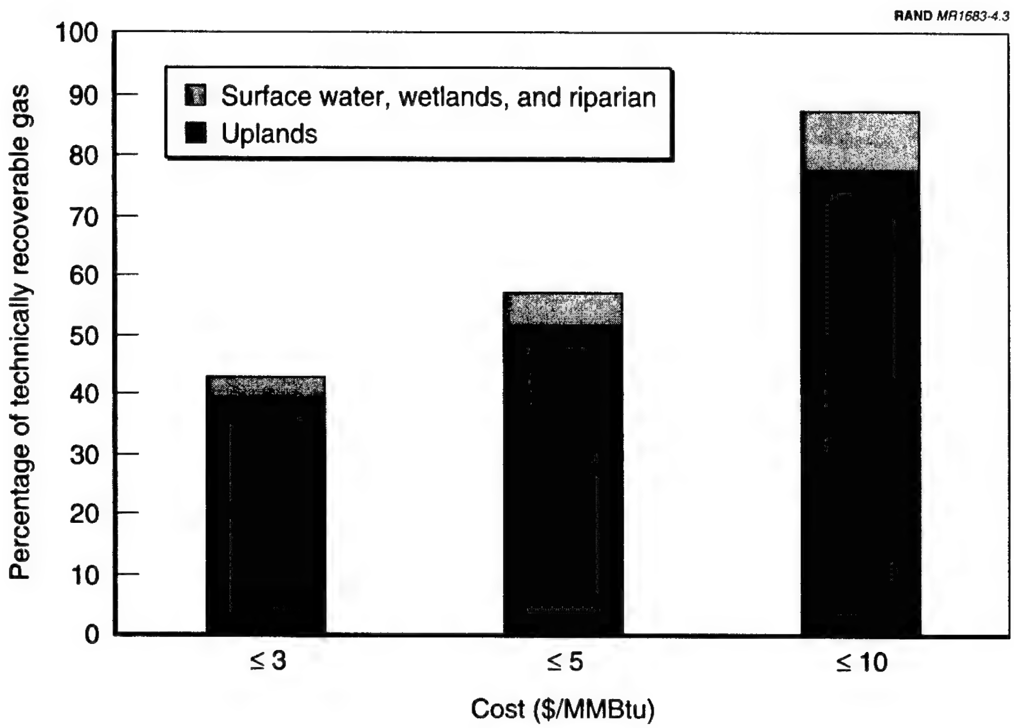


Figure 4.3—Surface Water, Wetlands, and Riparian Habitat Zone Overlay Results

HUMAN ENVIRONMENTAL CONSIDERATIONS

Along with various ecological issues, we consider environmental issues typically associated with the "human environment." From a human environmental perspective, concerns often center around maintaining the function of an area for some designated human use. In many instances, human environmental issues are closely tied

[8]Note that certain sensitive species occur in upland areas and are protected by many of the same conservation laws found in riparian areas.

to such ecological issues as air quality and water quality. Although much of our study area is sparsely populated, it includes a number of human settlements[9] with adjacent lands potentially affected by gas and oil development.

Gas and oil production can contribute to a risk of increased atmospheric haze, acid deposition on streams and vegetation, and various issues of human health that are correlated with degraded air quality. Many of these issues operate at larger regional areas that include sources and receptors well outside our study area and would require complex modeling that extends beyond the scope of this analysis.[10] Instead, we focus on local human environmental issues that can be related to lands within our study area. We present a simple measure that considers proximity to human settlements within the study area.

Proximity to Human Settlements. Air quality effects of some pollutants, such as carbon monoxide, fugitive dust, and less reactive toxics (e.g., benzene) occur at local levels, local being defined here as within approximately 20 kilometers. Ignoring specific factors affecting dispersion of emitted chemicals (e.g., source characteristics, climate, weather, and topography), we assume that development within areas uniformly enclosed by a 20 kilometer buffer around human settlements poses a potentially greater human health risk associated with degraded air quality. Thus, we consider two areas of relatively greater and relatively less concern for local air quality:

- Less than 20 kilometers from human settlements, and
- Greater than 20 kilometers from human settlements.

This same buffer may also enclose an area potentially susceptible to relatively higher impacts associated with noise, vibration, and local water supply and quality. Thus, this measure may also capture broader risks of potential land use incompatibility of gas and oil development nearer human settlements.

The spatial distribution of our proximity to human settlements measure according to these bins is shown in Map 4.4 in the maps section.

As shown in Table 4.2, areas within 20 kilometers of human settlements account for 5–8 percent of the resource at any cost, with the remaining 95–92 percent located beyond 20 kilometers of human settlements. Results for different economic costs are shown in Figure 4.4.

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[9]In 1990, Green River, Rock Springs, and Laramie had populations of 12,711, 19,050, and 26,287, respectively. The populations of most cities within the study area are less than 10,000 and over half of them are less than 2,000 (Wyoming Department of Administration and Information, 2002).

[10]Regional and global air quality issues associated with oil and gas extraction, or the cumulative effects of increased production in the study area, may be very important. Analysis of cumulative effects are often insufficiently treated by individual project-level analyses conducted as part of an environmental impact statement, required by the National Environmental Policy Act (NEPA). An appropriate quantitative analysis of cumulative, regional air quality issues associated with oil and gas extraction would require extensive air quality modeling similar to the ongoing work of the Western Regional Air Partnership.

Table 4.2

Natural Gas at Different Costs from USGS-Based Scenario Having Different Values of Proximity to Human Settlements

	Cost ($/MMBtu)						
	≤3		≤5		≤10		
Environmental Measure	% of ERR	% of TRR	% of ERR	% of TRR	% of ERR	% of TRR	% of TRR
Proximity to human settlements							
< 20 kilometers	5	2	6	3	8	7	8
≥ 20 kilometers	95	41	94	54	92	81	92
Sum	100	43	100	57	100	87	100

NOTES: % of ERR = [economically recoverable gas at listed price with specified value of environmental measure]/[economically recoverable gas at listed price]. % of TRR = [economically recoverable gas at listed price with specified value of environmental measure]/[technically recoverable gas]. Sums may differ slightly from totals because of rounding.

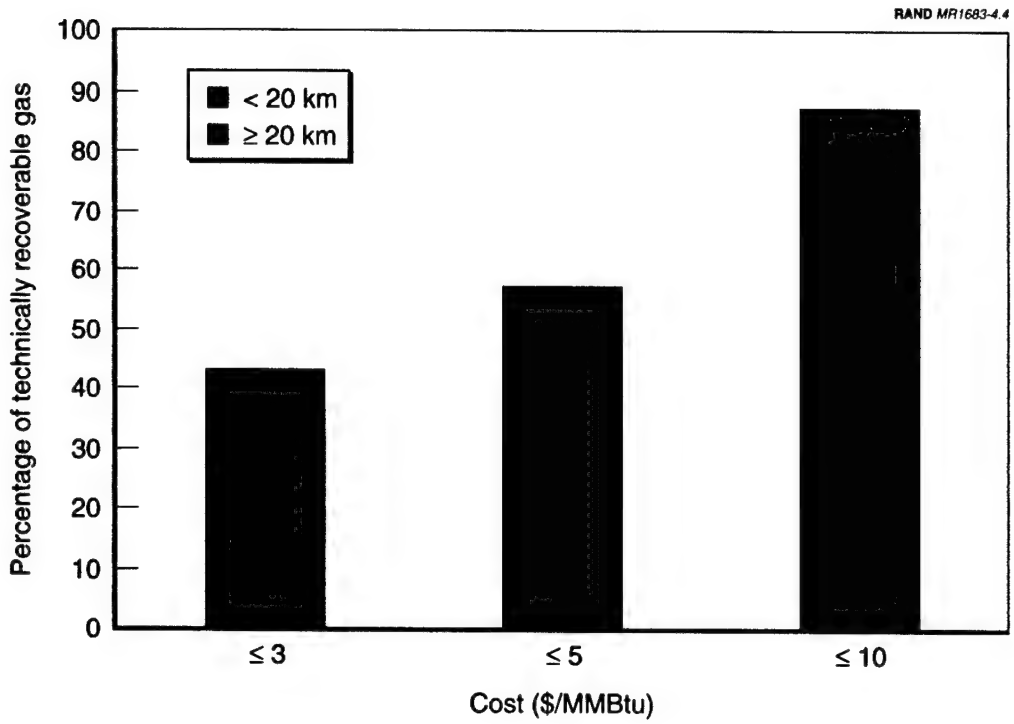

Figure 4.4—Proximity to Human Settlements Overlay Results

WATER QUALITY

Water quality is an important issue associated with gas and oil resource extraction and production. In Wyoming, approximately 65 percent of the population is served by surface water systems and the remainder is served by groundwater systems (U.S. Environmental Protection Agency, 2001). Agricultural and livestock operations also depend on water of sufficient quality. Contamination of water supply systems, ero-

sion and runoff into surface waters, and contamination of groundwater are among the potential risks associated with gas and oil production. In this analysis, we consider these risks as they relate to surface and groundwater quality.

Surface Water Quality

One measure of the potential risk of gas and oil production is the potential for runoff from a storm event or from surface discharge of fluids. Access to drilling areas, equipment staging, and rig set-up involve potential disturbance of vegetation and soils. This disturbance may lead to increased soil erosion and increased nutrient runoff and sedimentation of nearby and downstream waters. The potential for surface water contamination from runoff is correlated with a number of factors including slope, soil type, and type of vegetation cover (Lee, 1980).

Areas of lower slope, more permeable (sandy and gravelly) soils, and thicker undisturbed plant cover generally are associated with less runoff into surface waters. Greater slope, heavy clay soils, shallow soils over bedrock, and sparse vegetation often are associated with greater runoff potential. Although all of these factors correlate with runoff, we use slope as an important indicator of runoff potential.

Surface Slope. Using Bureau of Land Management lease stipulations (Potential Gas Committee, 2001; Advanced Resources International, Inc., 2001) and personal communication with Bureau of Land Management scientists[11] for guidance, we assume that unmitigated developments on slopes greater than 25 percent (approximately 14 degrees) are more likely to be associated with erosion. Additional mitigation measures are often required at slopes steeper than approximately 40 percent, so we also consider another slope cutoff at 40 percent (approximately 22 degrees) to further differentiate the land. Thus, we consider three bins for runoff and erosion potential due to varied slope:[12]

- Less than 25 percent,
- 25 to 40 percent, and
- Greater than 40 percent.

The spatial distribution of surface slope according to these bins is shown in Map 4.5 in the maps section.

Overlay results indicate that only about 4 percent of the gas at any cost is on lands with slopes greater than 40 percent (Table 4.3). Areas with slopes between 25 and 40 percent similarly contain about 4 percent of the gas, whereas more than 90 percent is

[11]Keith Andrews, Bureau of Land Management, Pinedale Field Office, personal communication, August 2002.

[12]We used a dataset representing slope for Wyoming that is based on a 90 meter digital elevation model, and resampled over 100 meter grid cells. Results of analysis at this resolution may underestimate runoff and erosion potential (e.g., gully erosion) because of topographic variation at a smaller than 1:250:000 scale.

on lands with slopes less than 25 percent. Overlay results for gas at different costs are shown in Figure 4.5.

Table 4.3

Natural Gas at Different Costs from USGS-Based Scenario Having Different Values of Water Quality Measures

	Cost ($/MMBtu)						
	≤3		≤5		≤10		
Environmental Measure	% of ERR	% of TRR	% of ERR	% of TRR	% of ERR	% of TRR	% of TRR
Surface slope							
> 40%	4	2	4	3	4	4	4
25–40%	4	2	4	2	4	4	4
< 25%	91	39	91	52	91	80	91
Sum	100	43	100	57	100	87	100
Aquifer recharge rate							
≥ 2 inches/year	9	4	9	5	9	8	9
< 2 inches/year	91	39	91	52	91	79	91
Sum	100	43	100	57	100	87	100
Depth to groundwater							
< 16 feet	9	4	10	6	12	10	12
16–56 feet	42	18	41	23	42	37	43
> 56 feet	49	21	49	28	46	40	45
Sum	100	43	100	57	100	87	100

NOTES: % of ERR = [economically recoverable gas at listed price with specified value of environmental measure]/[economically recoverable gas at listed price]. % of TRR = [economically recoverable gas at listed price with specified value of environmental measure]/[technically recoverable gas]. Sums may differ slightly from totals because of rounding.

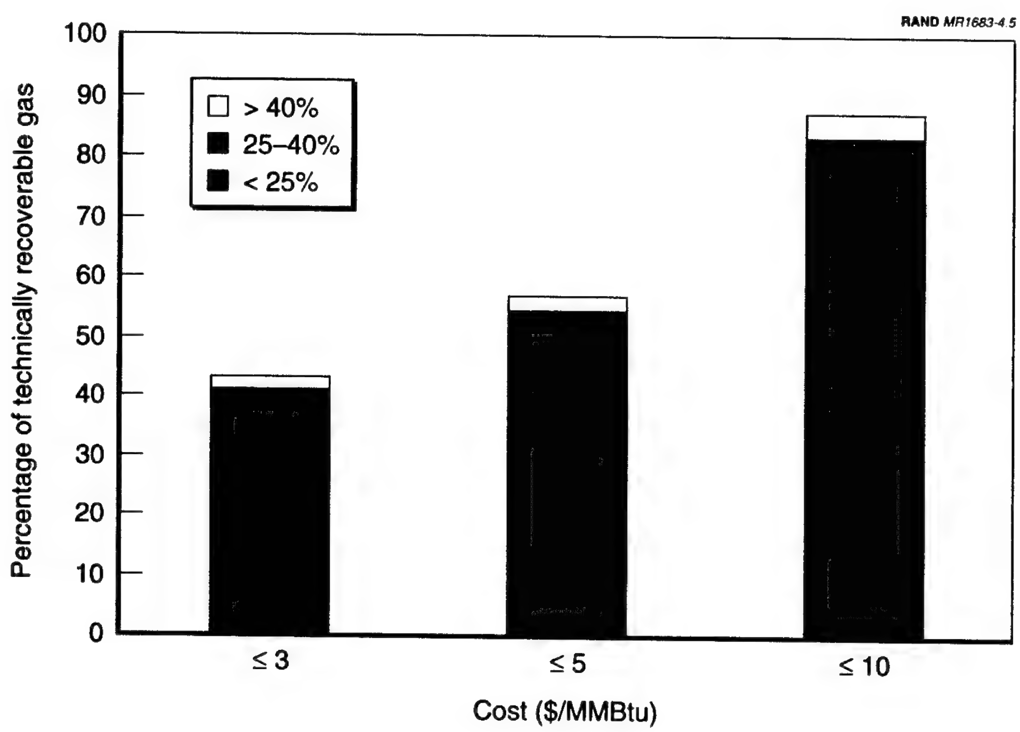

Figure 4.5—Surface Slope Overlay Results

Groundwater Quality

The process of drilling requires passage of formation fluids and process additives near and through groundwater aquifers above deeper gas and oil resources. Resource production, particularly coalbed methane production, can also generate large volumes of potentially hazardous formation fluids. Formation fluids may be discharged at the surface or reinjected into deep groundwater basin—the difference between these two methods has great implications for risk to surface or groundwater systems. In the Greater Green River Basin, reinjection is expected to predominate, and the risk of contaminating surface waters or initial groundwater aquifers is considerably less than if water were discharged at the surface. However, our methodology was derived with the intention of applying it to multiple basins. Thus, some measures, such as one assessing groundwater quality, which may not be critical in the Greater Green River Basin, may be more relevant in other basins.

Several types of groundwater vulnerability assessment models exist, including overlay and index methods, methods employing process-based simulation models, and statistical models (National Research Council, 1993). DRASTIC, one of the best-known index models, for example, considers measures of depth to groundwater, recharge rates, soils and aquifer media, and hydraulic conductivity and ranks areas based on weighted vulnerability scores. However, the DRASTIC method relies on judgment in proper weighting of parameters, which is often a source of debate. In our analysis, we do not combine measures in an attempt to comprehensively model groundwater vulnerability but instead focus on two measures—aquifer recharge rate and depth to groundwater—that generally correlate with an aquifer's potential risk of contamination from surface discharge (Johnston, 1988).

Aquifer Recharge. Recharge describes the infiltration of surface water into the soil and its percolation through the soil and unsaturated geologic material into the groundwater. It is measured as a flow rate and is expressed as an amount of water infiltrating to the water table in an area per unit of time (inches per year). Aquifer recharge varies according to amount of rainfall as well as soil and aquifer properties that characterize the unsaturated zone beneath the surface and above the water table (Johnston, 1988).

Recharge represents a primary transport mechanism of potential contaminants from the ground surface into the aquifer. In general, the more water available to recharge, the more susceptible the groundwater is to potential contamination.[13]

Recharge varies considerably across the study area, with relatively low recharge across much of the arid basin. Recharge across the basin is higher in areas characterized by certain surface water features (sluggish streams, lakes, and wetlands) and also increases dramatically with elevation in the mountainous areas. Review of

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[13]Note that there is a higher recharge rate where recharge begins to dilute contaminants, resulting in an inverse relationship between recharge and potential groundwater contamination; this dilution is not considered likely under natural conditions of the semiarid Wyoming landscape (Knight, 1994).

recharge data, which range from 0 to 58 inches per year, shows that three-quarters of the state of Wyoming (excluding Yellowstone National Park) is characterized by aquifer recharge of less than two inches per year.[14] We divide the data set into two groups on the basis of this third quartile score:

- Less than 2 inches per year, and
- Greater than 2 inches per year.

The spatial distribution of aquifer recharge according to these bins is shown in Map 4.6 in the maps section.

As Table 4.3 shows, areas with recharge less than two inches per year account for 91 percent of the resource recoverable at any cost. Areas with recharge of two inches or more per year account for 9 percent of the resource. Results for different costs are shown in Figure 4.6.

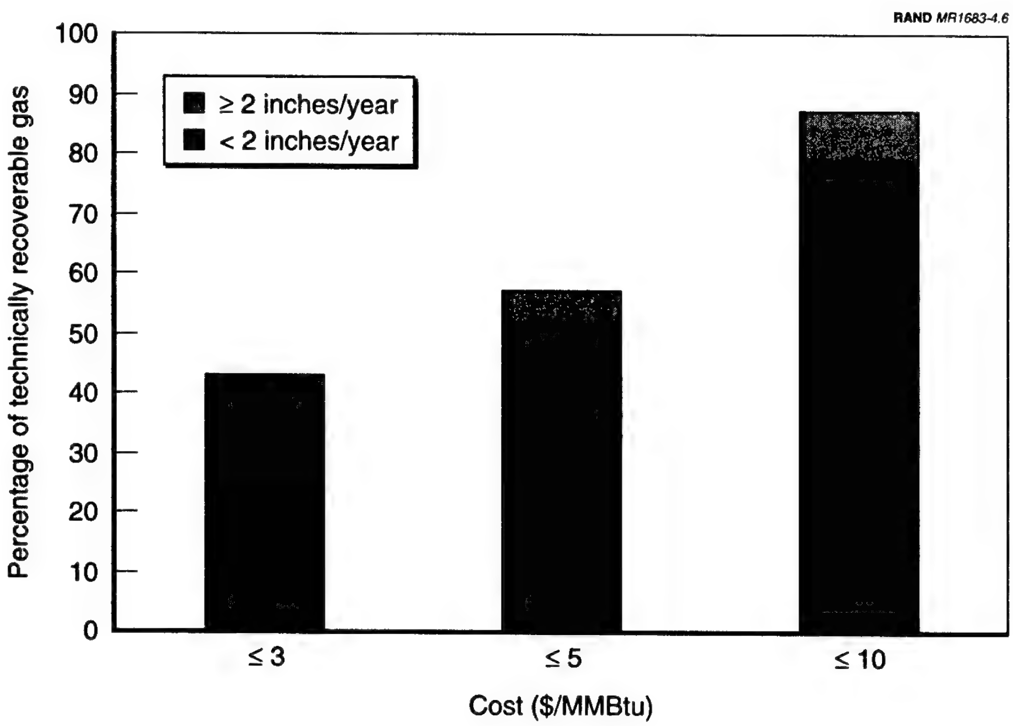

Figure 4.6—Aquifer Recharge Rate Overlay Results

[14]We use annual aquifer recharge data with 100 meter resolution from Munn and Arneson (1998). These data use average annual precipitation calculated by PRISM (Parameter-elevation Regressions on Independent Slopes Model) and published percolation percentages for documented soil and vegetation combinations to estimate recharge rates and classify 1:100,000-scale soil maps. PRISM is an analytical tool that uses point data, a digital elevation model, and other spatial datasets to generate gridded estimates of monthly, yearly, and event-based climatic parameters, such as precipitation, temperature, and dew point.

Depth to Groundwater. Along with the recharge rate, risk to groundwater quality may vary with depth to groundwater—shorter distances from the surface to the initial aquifer correlate with a greater risk from potential surface contamination.[15] Depth to initial groundwater in the Greater Green River Basin extends from areas where groundwater is as deep as 269 feet beneath the surface, with the distribution skewed toward shallower groundwater depths.[16] We grouped data into three bins accord-
ing to first and third quartile scores of the distribution (16 feet and 56 feet, respectively) as follows:

- Less than 16 feet,
- 16 to 56 feet, and
- Greater than 56 feet.

The spatial distribution of the depth to the initial groundwater according to these bins is shown in Map 4.7 in the maps section.

As shown in Table 4.3, lands with depths to initial groundwater of less than 16 feet account for 9–12 percent of the economically recoverable gas at any cost. Areas with depths to groundwater between 16 and 56 feet account for 42–43 percent, and areas with depths to groundwater exceeding 56 feet account for 46–49 percent of the resource. Overlay results for different costs are shown in Figure 4.7.

LEASE STIPULATIONS

In addition to the environmental measures derived for this study, we also conducted an overlay analysis for different classes of federal land lease stipulations. Recent attempts to assess energy resources in the Rocky Mountains have focused on inventorying resources subject to various legal access restrictions (lease stipulations) to resource development on federal lands (National Petroleum Council, 1999; Advanced Resources International, Inc., 2001). These studies have been controversial (e.g., Morton et al., 2002; LaTourrette et al., 2002). In their effort to identify impediments to energy development, these studies make some important assumptions that have implications for the effect of access restrictions on the available gas resource. These assumptions deal with economics, the resource base considered, restriction enforcement, technology, infrastructure, and drilling schedules. Some of these concerns

[15]The relationship between groundwater vulnerability and depth to groundwater is complicated by the possibility of preferential pathways and differences in soil and aquifer properties. More detailed analysis would be required to refine these influences.

[16]We use a dataset that represents depth to initial groundwater for Wyoming (excluding Yellowstone) at 100 meter resolution and is appropriate for analysis at 1:100,000 scale (Wyoming Water Resources Center, 1997). The data were created by spherical Kriging to interpolate a smooth surface between known data points obtained from the Wyoming State Engineer's Office well permit records from the early 1900s to 1992. Quality of well data was improved by some screening procedures and the final layer was expertly reviewed, but no quality assurance procedures have been performed as of 1996. The authors of this dataset warn that it should be used with extreme caution because of inaccuracies associated with township-range locational descriptions as well as the problems inherent in the State Engineer's Office database.

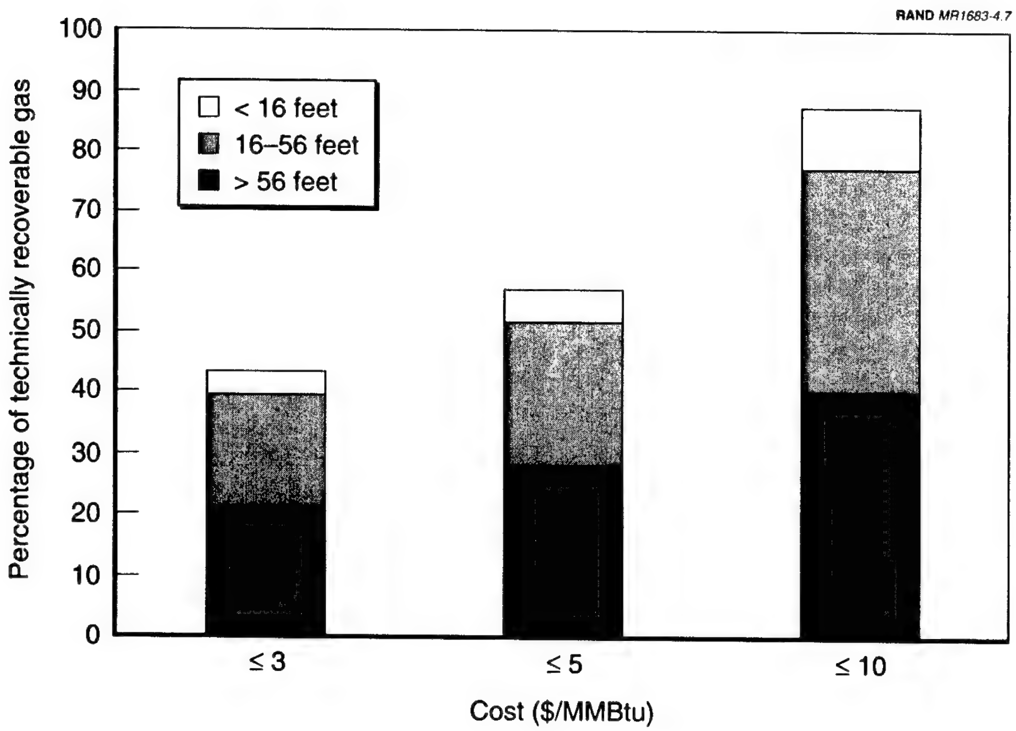

Figure 4.7—Depth to Initial Groundwater Overlay Results

have been addressed in a recently released study assessing access restrictions in five western basins, including a reanalysis of the Greater Green River Basin (U.S. Departments of Interior, Agriculture, and Energy, 2003). Overlays are presented here for the purposes of comparing results from different studies. These overlay results should be interpreted in light of the above concerns.

For this analysis we used the aggregated lease stipulation data compiled by the Department of Energy in its inventory of federal lands in the Greater Green River Basin (Advanced Resources International (ARI), Inc., 2001). GIS shape files of aggregated stipulations were overlaid with the gas distribution in the area included in the intersection of the RAND and Department of Energy study areas. Overlays were calculated for areas subject to no access, restricted access, standard lease terms, and nonfederal land. The distribution of these categories throughout the Greater Green River Basin is shown in Map 4.8 in the maps section.

Results of the overlay analysis are presented in Table 4.4 and Figure 4.8. Our analysis shows that about 11 percent of the potential gas resources is on land classified as no access and 30 percent of the gas is on land subject to restricted access. The remainder is on land subject to standard lease terms or not federally owned. Compared to results presented in Advanced Resources International (2001), our results show that a higher fraction of the gas is subject to standard lease terms and a lower fraction is subject to access restrictions or no access. Both analyses use the same distribution of lease stipulations, so the discrepancy reflects differences in the gas re-

Table 4.4

Percentage of Technically Recoverable Gas from USGS-Based Scenario Subject to Different Categories of Lease Stipulations

Stipulation Category[a]	This Study	This Study, Federal Land Only	ARI (2001)
No access[b]	11	17	30
Restricted access[c]	30	44	39
Standard lease terms	59[d]	40	32

[a]Distribution of stipulations is taken from Advanced Resources International, Inc. (2001).

[b]No access includes no access statutory, no access administrative, and no surface occupancy categories.

[c]Restricted access includes all timing lease stipulations and controlled surface use categories.

[d]Includes gas on nonfederal land.

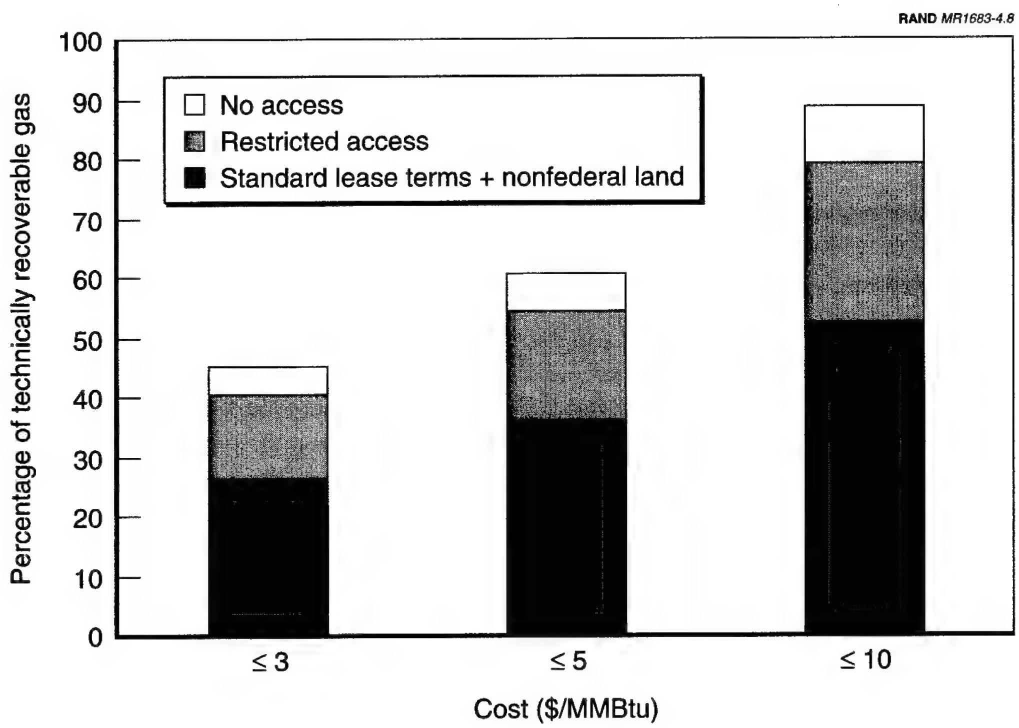

Figure 4.8—Lease Stipulation Category Overlay Results

source base and spatial distribution used in each analysis. Some of these differences stem from using different data sources and allocation procedures. In addition, the results presented in this report differ in that they include proved reserves, reserve appreciation, and gas underlying nonfederal lands, which are not included in Advanced Resources International (2001). Nonfederal lands are generally considered accessible to industry, so we include nonfederal lands with the standard lease terms category. Including them increases the fraction of resources subject to standard lease terms and decreases the fraction of resources subject to access restrictions.

Our analysis shows that approximately 31 percent of the technically recoverable gas in the Greater Green River Basin underlies nonfederal lands. Recalculating our overlays using only federal lands moves the results closer to those of Advanced Resources International (Table 4.4).[17]

UNCERTAINTY IN OVERLAY RESULTS

Uncertainties in the overlay results are difficult to estimate because the uncertainties in the input data are poorly constrained. Uncertainty derives from two sources: the positional uncertainty in the gas and environmental measure distributions and uncertainty in the data values assigned to each point. The effect of the positional uncertainty can be qualitatively evaluated by comparing the results of overlays of a single environmental measure distribution with the various gas distributions generated at different costs. In terms of the relative proportion of gas in different environmental bins, overlay results for gas distributions generated at different costs agree to within 5 percent (% of ERR in Tables 4.1–4.3). This suggests that variations in the locations of data elements do not significantly affect the overlay results.

In principle, the environmental measure distributions could be perturbed by an estimated uncertainty to determine the sensitivity of the overlay results to the data values. The extent to which the overlay results differed from the overlay with the initial distribution would then give an estimate of the sensitivity. However, because no uncertainty estimates were provided for the data values of the input environmental data, we were unable to estimate the effect they may have on the overlay results. Although the environmental data may be the best available, we can suggest only that results are preliminary and are to be used for general strategic guidance purposes.

SUMMARY

The overlay results shown provide estimates of the amount of resource that satisfies different levels of both economic and environmental criteria and are summarized in Tables 4.1–4.3. In general, we find that relatively small fractions of the technically or economically recoverable natural gas in the Greater Green River Basin occur in areas of relatively higher potential environmental concern with respect to the environmental measures we considered. For the ecological measures, 18 percent of the economically recoverable natural gas is in areas with predicted species richness above the median value and 11 percent is in aquatic or riparian areas. Less than 8 percent of the gas occurs within close proximity of human settlements. Of the water quality measures, only 8 percent occurs in areas with slopes greater than 25 percent, and ar-

[17]The government's inventory of natural gas subject to various lease stipulations has been revised in the recently released Energy Policy and Conservation Act (EPCA) study (U.S. Departments of Interior, Agriculture, and Energy, 2003). That study finds that 10 percent, 29 percent, and 61 percent of the gas in the Greater Green River Basin is subject to no access, restricted access, and standard lease terms, respectively. The EPCA study results cannot be compared to the overlay results presented in this report because they are based on different distributions of lease stipulations. The differences between the results of the initial Department of Energy study (Advanced Resources International, Inc., 2001) and the EPCA study stem from a number of changes in the approaches used, such as including proved reserves and using a different geographic area.

eas with high aquifer recharge rates and shallow groundwater contain 9 percent and 12 percent, respectively, of the gas in the basin. From 14 to 64 percent of the gas is located in buffer zones around sensitive species observed locations, making this measure outstanding in having a relatively higher fraction of gas in the potentially more sensitive bin.

The interpretation of the environmental measures is less straightforward than the results of the economic analysis, in terms of both the relative importance of the different values of a single measure and the relative importance of the different measures. As discussed above, we have endeavored to select an appropriate suite of environmental measures and to bin values of those measures in meaningful ways. We do not attempt to integrate the separate measures into a single index. For our purposes, it was important to use environmental measures consisting of only professionally reviewed, publicly available data from reliable sources. Combining these data into an integrated index could provide the appearance of simplicity and allow easy ranking of areas, but in reality such an approach would introduce new assumptions and uncertainties, potentially undermining the reliability of any index. Note also that the bin values assigned for the various measures are not necessarily based on established significance thresholds. Setting such thresholds is a task best left to agency discretion and more thorough scientific research than is possible within the scope of this study.

We therefore present the results of the overlay analysis with the environmental measures as an example of how our proposed methodology can be used. Our intention is to develop a systematic framework with which to examine the effect of various environmental measures on the resource assessment. Given this framework, different stakeholders can approach the problem with measures and bins of interest and assess the resources accordingly.

Chapter Five

CONCLUSIONS

This report presents a methodology to enhance the regional assessment of gas and oil resources for the purposes of strategic (long-term and large-scale) planning of energy resource development on public lands. We apply the methodology to a case study of the Greater Green River Basin in southwestern Wyoming. However, the approach developed here is intended to be applicable to other areas of the Rocky Mountains as well as other regions of the nation.

The purpose of gas and oil resource assessments is to provide decisionmakers with a scientifically informed estimate of the quantity and spatial extent of the resource. In standard practice, the assessment is based on a measure called the "technically recoverable resource," which is the resource accessible according to some definition of technological capability.

In the methodology presented in this report, we develop additional criteria related to the economic costs of production and transport and measures of environmental concern. We then overlay these criteria on the base estimate of technically recoverable resource to provide a more complete view of the amount of resource that could potentially be developed under various cost assumptions. The information produced can help federal and state land managers and policymakers at all levels set priorities and strategically plan for long-term resource use.

BENEFITS

This methodology offers several supplementary benefits to decisionmakers over the traditional resource assessment:

- Allocating resources to subplays and distinguishing between separate resource categories allows stakeholders to envision the intra-basin spatial distribution of resources.
- Including economic criteria enables federal land managers and other decisionmakers to consider relative priorities for land use based on economic viability of the resource.
- Overlaying the distribution of resources under various economic assumptions with distributions of land characteristics reflecting potential environmental concerns provides a more complete view of actual environmental assets—distinct

from legal access restrictions—coincident with areas of potential resource development.

- The methodology can be adapted to become an interactive decisionmaking tool, in which modeling and planning assumptions can be varied and their effect on resource estimates examined.
- The methodology offers an additional tool for energy forecasters to provide further spatial and temporal refinements to their long-term resource estimates.

LIMITATIONS

The methodology also has limitations that should be kept in mind when interpreting results.

- Scale and resolution make this method suitable for broad-scale assessment and planning purposes but not for specific local scale analyses of resource potential or environmental impacts.
- The production cost functions, spatial distribution of resources, and overlay results are predicated on several simplifying assumptions. The sensitivity of results to these assumptions is an important consideration in interpreting the results.
- The economic results represent current estimates and will evolve with time. Long lead times for planning based on short-term estimates of economics should be accounted for in the planning process through the use of bounding scenarios.
- Uncertainty in the effect of gas or oil development on environmental measures means that these overlays should be used to signal the need for further study and analysis of likely impacts and opportunities for mitigation.

In addition, this method produces information that supplements other sources of information about the resource and should not be used in isolation. It is not designed nor should it be used to replace detailed economic analyses of resource potential on specific leases or NEPA-like environmental analyses.

INTERPRETATION OF GREEN RIVER BASIN RESULTS

The case study illustrates the use of the methodology to assess natural gas resources in the Greater Green River Basin. These results are instructive for developing the methodology further and providing insights that may help inform strategic energy resource planning in this basin. Results are summarized in Table 5.1.

Depending on the economic scenario, 35 to 45 percent of the natural gas resources could be produced profitably at a market price of $3/MMBtu, which is similar to recent prices in Wyoming. Up to 65 percent could be profitably produced if the market price were $5/MMBtu. If electric utilities or state energy planners had this information available for all basins in the region, they could better plan their long-term resource use by having a more realistic view of availability based on production costs.

Table 5.1

Summary of Results

		Cost ($/MMBtu) 3	5
Economically recoverable gas	Tcf:	47–68	70–104
	% of TRR:	35–45	52–65
Percentage of economically recoverable gas on lands			
With high terrestrial vertebrate species richness[a]		17	17
Within 2,000 m of sensitive species locations		14	14
Within 6,500 m of sensitive species locations		65	65
With surface water, wetlands, or riparian habitats		9	10
Near human settlements		5	6
With high surface slope[b]		8	8
With high aquifer recharge rate[c]		9	9
With shallow groundwater[d]		9	10
Subject to no access[e]		10	10
Subject to restricted access[e]		31	30

NOTES: Ranges for economically recoverable gas reflect different economic scenarios. Results for environmental measures are for the USGS-based scenario only; percentages shown do not necessarily apply to separate areas and so are not additive.

[a] >119 species/area.

[b] >25%.

[c] >2 inches/year.

[d] <16 feet.

[e] Results are based on aggregated lease stipulations from Advanced Resources International, Inc. (2001) and are not related to environmental measures analyzed in this study.

Likewise, the Energy Information Administration could use this more detailed information in its price and supply forecasts.

When examined in terms of spatial context, our economic analysis provides further insight. The spatial analysis shows that the distribution of technically recoverable gas throughout the basin is uneven, with higher gas concentrations in the western and central areas of the basin (Map 2.2). When considering economically recoverable gas, the spatial distribution is broadly similar to that of the technically recoverable gas and the concentrations vary relatively smoothly with cost on the basinwide scale (see maps). In detail, however, concentrations in some areas drop off much more quickly than in others as the price decreases. Thus, the fraction of gas that is economically recoverable at a given price varies substantially from place to place. For example, at $3/MMBtu, the ratio of economically to technically recoverable gas in particular areas is far smaller than the basinwide value of 35 to 45 percent. This is most apparent for portions of the Great Divide and Washakie Basins, where this ratio is lower than 1 percent (see Maps 2.2 and 3.1). In other places, the ratio of economically to technically recoverable gas exceeds the basinwide average and can approach one. These results illustrate the value of the combination of economic and spatial analyses: Concentrations of economically recoverable resources do not necessarily correlate directly with the concentrations of technically recoverable resource. By using transparent economic and other quantitative criteria, the methodology enables decisionmakers to establish a credible basis for more spatially refined priorities for access and permitting.

The environmental measures analysis provides additional understanding of the gas resource in the Greater Green River Basin. A useful way to consider these results is in terms of the relative proportion of gas resources at any cost on lands having different values of environmental measures. These results are presented in Table 5.1. Our analysis indicates that these proportions are nearly independent of economic considerations—the overlay results for gas distributions at different costs differ by less than 5 percent.

For the most part, the concentrations of economically recoverable gas are in areas having values of environmental measures of relatively lesser concern. As with the economic evaluation, however, environmental overlay results for certain areas within the basin differ from the basinwide average values shown in Table 5.1. A few areas, such as north of the LaBarge Platform and parts of the Great Divide Basin, have relatively high gas densities that coincide with riparian habitats, high terrestrial vertebrate species richness, and shallow groundwater. Such insights may be particularly useful in areas, such as north of the LaBarge Platform, that may appear quite promising judging by the economic analysis alone.

The connection between environmental measures and likelihood of environmental impact is complex, and actual environmental impacts would not necessarily result from development on lands with individual measures above (or below) a specified level of concern. However, our results suggest that these lands might be less attractive than other lands for development. For example, there may be more costs associated with mitigating potential impacts on lands close to surface water resources. This information would be useful to public land managers who may need to prioritize their efforts in permitting lands for exploration and production.

The results generated from this approach can provide decisionmakers with more robust information about natural resources that can help guide strategic resource planning, help prioritize difficult decisions that are being made about access to federal lands, and help understand the potential consequences of decisions.

IMPLICATIONS FOR THE ROCKIES

The primary objective of this study was to develop a methodology that incorporates economic (including development, production, and infrastructure) and environmental considerations into energy resource assessments. The methodology was developed with a focus on the Greater Green River Basin because of its overall high resource potential and its diverse range of deposit types and depths, which results in a large range of development and production costs. In doing so, we have highlighted some aspects of natural gas resources in the Greater Green River Basin that may not be directly evident from technically recoverable resource assessments. However, the value of this approach is expected to be even more evident when it has been applied to all the basins in the Rocky Mountains and eventually to all basins in the country. Just as a basinwide evaluation using a consistent methodology allows federal land managers to compare and prioritize areas within the Greater Green River Basin, a Rockies-wide evaluation will allow these managers to make the same type of comparisons and prioritizations among areas within different basins.

Given the continuing increase in demand for natural gas and the practical limitations on meeting this demand by increasing imports, gas production in the United States is expected to increase substantially in the coming years. Industry and government are looking to resources in the Rocky Mountain region, the majority of which underlie federal land, to generate much of this supply. Federal land managers are thus facing demands for substantial increases in the amount of natural gas production in the Rockies. Efforts are already under way to expedite the approval process of energy-related developments on federal lands (U.S. Bureau of Land Management, 2001). It is therefore increasingly important that attention be paid to strategic land use planning.

ISSUES FOR FURTHER DEVELOPMENT

The methodology proposed in this work represents a first step toward the goal of expanding the scope of energy resource assessments to help improve decisionmaking. The approach represents a substantial change in the way resource assessments are conducted as well as in how they may be used to inform policy. As such, it is preliminary in several aspects and will require continued development to improve its utility. Further development should focus on several areas:

Develop Environmental Measures

The environmental measures proposed here represent a first-order attempt to provide a framework to characterize energy resources in terms of the potential environmental impacts associated with their development. To be more effective, further research must be conducted to address three general limitations. More discussion of these limitations is included in Chapter Four.

- Refine the selection of measures to cover the relevant range of potential environmental impacts associated with gas and oil development. Examples not addressed in this report include measures to capture regional air quality and cumulative impacts over time and space.
- Refine the relationship between the measure values and potential impacts. The current approach uses primarily a statistical analysis to assess relative concern within the study area. An empirical approach based on an understanding of environmental impacts and gas and oil activities would improve the method.
- Develop a scientifically informed means to combine the information from multiple measures, through either integrating or ranking. A combined measure would be more manageable in terms of understanding environmental considerations of different resources.

Addressing each of these points will require consultations with public land managers about their information needs; consultations with landowners, producers, leaseholders, and environmental and other conservation interests; and research and recommendations from the scientific community. The unifying objective would be to

apply relevant information and knowledge to a systematic approach that can be used at a regional planning scale.

Refine the Appropriate Scale of Applicability

The objective of our approach is to conduct an assessment at the basin scale to help guide decisions regarding subbasin scale areas. The data used for the economic and environmental evaluations come from a number of sources having differing resolutions and accuracies. This raises the question of the scale at which it is appropriate to draw conclusions about different areas within the basin. As discussed in Chapter Three, resolution of about 30 miles may be meaningful for the economic analysis. However, this resolution may not be compatible with the resolution of the environmental data. It also does not consider the effect of several uncertainties, including the allocation of resources to subplays. A better understanding of the relevant scale for decisionmaking is needed to guide the implementation of this approach. Improved data acquisition with more consistency in scaling may improve estimates of the resolution associated with the outputs of the proposed method.

Better Incorporate the Methodology into Decisionmaking

In proposing our approach, we have outlined particular ways the information can be used to inform policy in the decisionmaking process. However, we recognize that aspects of the methodology may need to be modified to best meet the objectives of the decisionmaking process. For example, there is currently no precedent for interpreting economically recoverable resources. One possibility is to link them to Energy Information Administration price projections. Another question is how to integrate the environmental measures with the existing environmental analysis processes, including NEPA and designation of lease-specific access restrictions.

The methodology presented in this study provides a more complete understanding of energy resource characteristics by accounting for the economics, or real dollar costs, associated with production and moving some of the environmental protection considerations, or social costs, upstream in the decisionmaking process. In the process, it is meant to help define the potential for productivity and the anticipated environmental considerations of gas and oil resources. Such information is intended to help guide government officials and other stakeholders in land use planning, development of energy policies, and energy development and utilization planning.

Appendix

SUBPLAYS, AREAS, AND TECHNICALLY RECOVERABLE RESOURCES USED IN THE ANALYSIS

Table A.1a

Subplays, Areas, and Technically Recoverable Resource Assessments Used in the Analysis: USGS-Based Scenario

	Area (square miles)				Proved Reserves		Gas (bcf)			Liquids [b] (MMbbl)		
Subplay[a]	Producing	Extension	New Field	Total	Gas (Bcf)	Liquids[b] (MMbbl)	Res App	Undiscovered	Total	Res App	Undiscovered	Total
Axial Uplift	106	12	3,355	3,473	4	3	10	33	47	14	15	31
Basin Margin Anticline	180	203	2,744	3,127								
Tertiary-Upper Cretaceous					191	3	485	111	786	20	12	35
Lower Cretaceous					30	1	76	41	147	4	10	15
Miscellaneous					3	0	8	5	17	0	1	2
Cherokee Arch	118	31	802	951								
Tertiary					61	2	156	109	327	8	1	10
Upper Cretaceous					142	0	362	5	508	3	0	3
Lower Cretaceous					2	0	6	3	11	0	0	0
Jurassic and older					41	0	105	61	207	0	0	0
Miscellaneous					8	0	21	53	82	0	0	0
Deep Basin	23	377	1,074	1,474	565	0	250	0	815	0	0	0
Moxa Arch	691	356	507	1,554								
Tertiary					36	2	92	46	175	10	1	13
Upper Cretaceous					99	11	258	66	423	51	1	63
Lower Cretaceous					1,960	16	5,004	329	7,292	110	16	142
Jurassic—Penn					0	0	1	3	5	0	3	3
Miscellaneous					29	2	77	76	182	9	1	12
Platform	372	164	6,446	6,982								
Cretaceous					9	1	22	9	40	4	13	18
Pre-Cretaceous					239	52	646	38	923	236	5	294
Miscellaneous					13	13	35	17	65	60	22	95
Rock Springs Uplift	240	61	2,082	2,383								
Tertiary					0	0	0	0	0	0	0	0
Upper Cretaceous					108	5	274	158	539	22	22	49
Lower Cretaceous					81	0	203	109	393	1	5	5
Jurassic —Permian					11	1	29	9	49	3	21	25
Pennsylvanian					211	4	580	168	959	48	10	62
Miscellaneous					24	3	61	52	137	12	1	16
Subthrust	0	0	1,479	1,479	0	0	0	116	116	0	22	22
Jackson Hole	0	0	4,286	4,286	0	0	0	48	48	0	8	8

Table A.1a (continued)

	Area (square miles)				Proved Reserves		Gas (bcf)			Liquids [b] (MMbbl)		
Subplay[a]	Producing	Extension	New Field	Total	Gas (Bcf)	Liquids[b] (MMbbl)	Res App	Undiscovered	Total	Res App	Undiscovered	Total
Cloverly-Frontier Tight												
1 (0–15,000 feet)	0	0	1,910	1,910	0	0	0	10,625	10,626	0	116	116
2 (15,000–17,000)	0	0	3,529	3,529	0	0	0	13,552	13,552	0	136	136
3 (17,000–19,000)	0	0	2,829	2,829	0	0	0	7,328	7,328	0	73	73
4 (19,000–21,000)	0	0	1,911	1,911	0	0	0	3,271	3,271	0	33	33
5 (>21,000)	0	0	3,129	3,129	0	0	0	3,627	3,627	0	32	32
Mesaverde Tight												
1 (0–9,000)	189	137	733	1,059	466	6	0	10,932	11,398	26	185	216
2 (9,000–11,000)	276	235	1,941	2,452	747	10	0	21,293	22,040	41	360	412
3 (11,000–13,000)	93	81	1,353	1,527	161	1	0	10,206	10,366	9	52	62
4 (13,000–15,000)	13	12	1,457	1,482	12	0	0	7,035	7,046	1	36	37
5 (>15,000)	0	0	1,576	1,576	0	0	0	5,426	5,426	0	11	11
Lewis Tight												
1 (0–10,000)	137	112	1,047	1,296	241	3	0	7,573	7,815	14	99	115
2 (10,000–12,000)	35	29	1,225	1,289	60	1	0	5,831	5,891	3	87	92
3 (>12,000)	17	16	1,854	1,887	13	0	0	6,186	6,200	1	13	13
Fox Hills-Lance Tight												
1 (0–10,000)	61	77	960	1,098	920	9	0	4,484	5,404	40	43	92
2 (10,000–12,000)	14	17	1,123	1,154	50	1	0	2,739	2,789	2	28	31
3 (>12,000)	32	39	1,946	2,017	66	1	0	3,210	3,276	3	33	37
Fort Union Tight												
1 (0–10,000)	0	0	291	291	0	0	0	636	636	0	8	8
2 (10,000–12,000)	0	0	251	251	0	0	0	371	371	0	4	4
Rock Springs Coalbed	0	0	430	430	0	0	0	693	693	0	0	0
Iles Coalbed	0	0	1,158	1,158	0	0	0	377	377	0	0	0
Williams Fork Coalbed	0	0	730	730	1	0	0	1,385	1,386	0	0	0
Almond Coalbed	0	0	3,560	3,560	0	0	0	795	795	0	0	0
Lance Coalbed	0	0	2,946	2,946	0	0	0	230	230	0	0	0
Fort Union Coalbed	0	0	10,306	10,306	0	0	0	408	408	0	0	0
Total	2,597	1,957	70,970	75,524	6,603	148	8,760	129,878	145,242	756	1,538	2,443

[a]Conventional plays are divided into subplays according to stacked stratigraphic units, each with an identical surface aerial extent. Conventional subplays thus were used for calculating resource amounts and costs but were not distinguished spatially. Tight sandstone plays are divided into subplays according to depth intervals (depths listed n feet). Tight sandstone subplays have unique surface aerial extents and thus were used for calculating resource amounts and costs and were distinguished spatially. There are 50 subplays used to define resource amounts and costs, 33 of which are distinguished spatially.

[b]Liquids = crude oil plus natural gas liquids.

Table A.1b

Subplays, Areas, and Technically Recoverable Resource Assessments Used in the Analysis: NPC-Inspired Scenario

	Area (square miles)				Proved Reserves		Current Technology						Advanced Technology					
							Gas (bcf)			Liquids [b] (MMbbl)			Gas (bcf)			Liquids [b] (MMbbl)		
Subplay [a]	Producing	Extension	New Field	Total	Gas (Bcf)	Liquids [b] (MMbbl)	Res App	Undiscovered	Total	Res App	Undiscovered	Total	Res App	Undiscovered	Total	Res App	Undiscovered	Total
Axial Uplift	106	12	3,355	3,473	4	3	10	44	58	2	11	15	10	49	63	2	14	19
Basin Margin Anticline	180	203	2,744	3,127														
Tertiary—Upper Cretaceous					191	3	475	3,430	4,095	7	44	54	475	3,843	4,509	7	51	61
Lower Cretaceous					30	1	74	931	1,035	2	24	26	74	1,043	1,147	2	28	30
Miscellaneous					3	0	8	111	122	0	2	3	8	124	136	0	3	3
Cherokee Arch	118	31	802	951														
Tertiary					61	2	153	487	702	2	3	7	153	546	761	2	4	8
Upper Cretaceous					142	0	356	598	1,096	1	2	3	356	671	1,168	1	2	4
Lower Cretaceous					2	0	5	24	32	0	0	0	5	27	34	0	0	0
Jurassic and older					41	0	104	349	493	0	0	0	104	391	535	0	0	0
Miscellaneous					8	0	20	287	316	0	1	1	20	322	350	0	1	1
Deep Basin	23	377	1,074	1,474	565	0	14,689	6,693	21,947	0	0	0	14,689	7,500	22,754	0	0	0
Moxa Arch	691	356	507	1,554														
Tertiary					36	2	91	413	539	2	4	8	91	462	589	2	5	9
Upper Cretaceous					99	11	255	587	941	10	6	26	255	658	1,012	10	6	27
Lower Cretaceous					1,960	16	4,922	604	7,486	49	15	79	4,922	677	7,559	49	18	83
Jurassic—Penn					0	0	1	89	91	0	6	6	1	100	102	0	7	8
Miscellaneous					29	2	75	527	631	2	2	6	75	591	695	2	2	6
Platform	372	164	6,446	6,982														
Cretaceous					9	1	22	16	46	1	10	12	22	18	48	1	13	15
Pre-Cretaceous					239	52	621	621	1,481	48	16	115	621	696	1,556	48	18	118
Miscellaneous					13	13	33	94	140	10	17	41	33	106	151	10	23	46
Rock Springs Uplift	240	61	2,082	2,383														
Tertiary					0	0	0	1	1	0	0	0	0	1	1	0	0	0
Upper Cretaceous					108	5	269	655	1,032	5	19	29	269	734	1,111	5	25	34
Lower Cretaceous					81	0	200	455	735	0	4	4	200	510	790	0	5	5
Jurassic - Permian					11	1	28	40	80	1	15	17	28	46	85	1	20	22
Pennsylvanian					211	4	570	697	1,479	35	39	78	570	782	1,563	35	44	83
Miscellaneous					24	3	59	388	470	2	1	5	59	434	517	2	1	5
Subthrust	0	0	1,479	1,479	0	0	0	2,604	2,604	0	41	41	0	2,918	2,918	0	50	50
Jackson Hole	0	0	4,286	4,286	0	0	0	2,818	2,818	0	33	33	0	3,158	3,158	0	38	38

Table A.1b(continued)

	Area (square miles)				Proved Resources		Current Technology						Advanced Technology					
							Gas (bcf)			Liquids[b] (MMbbl)			Gas (bcf)			Liquids[b] (MMbbl)		
Subplay[a]	Producing	Extension	New Field	Total	Gas (Bcf)	Liquids[b] (MMbbl)	Res App	Undiscovered	Total	Res App	Undiscovered	Total	Res App	Undiscovered	Total	Res App	Undiscovered	Total
Cloverly-Frontier Tight																		
1 (0–15,000 feet)	0	0	1,910	1,910	0	0	2	8,125	8,127	0	89	89	2	10,620	10,622	0	116	116
2 (15,000–17,000)	0	0	3,529	3,529	0	0	1	10,381	10,382	0	104	104	1	13,565	13,565	0	136	136
3 (17,000–19,000)	0	0	2,829	2,829	0	0	0	5,588	5,588	0	56	56	0	7,306	7,306	0	73	73
4 (19,000–21,000)	0	0	1,911	1,911	0	0	0	2,497	2,497	0	25	25	0	3,265	3,265	0	33	33
5 (>21,000)	0	0	3,129	3,129	0	0	0	2,766	2,766	0	24	24	0	3,616	3,616	0	31	31
Mesaverde Tight																		
1 (0–9,000)	189	137	733	1,059	466	6	1,191	3,966	5,623	24	67	97	1,191	5,163	6,820	24	87	117
2 (9,000–11,000)	276	235	1,941	2,452	747	10	1,906	7,665	10,318	39	130	179	1,906	9,987	12,640	39	169	218
3 (11,000–13,000)	93	81	1,353	1,527	161	1	410	3,797	4,367	3	19	24	410	4,925	5,496	3	25	29
4 (13,000–15,000)	13	12	1,457	1,482	12	0	29	2,502	2,543	0	13	13	29	3,266	3,307	0	17	17
5 (>15,000)	0	0	1,576	1,576	0	0	0	1,906	1,906	0	4	4	0	2,492	2,492	0	5	5
Lewis Tight																		
1 (0–10,000)	137	112	1,047	1,296	241	3	597	4,310	5,149	10	56	69	597	5,592	6,430	10	73	86
2 (10,000–12,000)	35	29	1,225	1,289	60	1	148	3,276	3,484	3	49	53	148	4,258	4,466	3	64	68
3 (>12,000)	17	16	1,854	1,887	13	0	33	3,381	3,427	0	7	7	33	4,410	4,457	0	9	9
Fox Hills-Lance Tight																		
1 (0–10,000)	61	77	960	1,098	920	9	2,258	4,921	8,098	28	47	84	2,258	6,272	9,450	28	60	97
2 (10,000–12,000)	14	17	1,123	1,154	50	1	122	1,490	1,662	2	15	18	122	1,928	2,100	2	20	22
3 (>12,000)	32	39	1,946	2,017	66	1	161	1,355	1,581	2	14	17	161	1,725	1,951	2	18	21
Fort Union Tight																		
1 (0–10,000)	0	0	291	291	0	0	0	782	782	0	10	10	0	1,023	1,023	0	13	13
2 (10,000 - 12,000)	0	0	251	251	0	0	0	783	783	0	8	8	0	1,023	1,023	0	10	10
Rock Springs Coalbed	0	0	430	430	0	0	0	769	769	0	0	0	0	991	991	0	0	0
Iles Coalbed	0	0	1,158	1,158	0	0	0	418	418	0	0	0	0	539	539	0	0	0
Williams Fork Coalbed	0	0	730	730	1	0	0	1,538	1,538	0	0	0	0	1,981	1,982	0	0	0
Almond Coalbed	0	0	3,560	3,560	0	0	0	882	882	0	0	0	0	1,137	1,137	0	0	0
Lance Coalbed	0	0	2,946	2,946	0	0	0	255	255	0	0	0	0	328	328	0	0	0
Fort Union Coalbed	0	0	10,306	10,306	0	0	0	453	453	0	0	0	0	583	583	0	0	0
Total	2,597	1,957	70,970	75,524	6,603	148	29,898	97,369	133,870	290	1,052	1,491	29,898	122,399	158,901	290	1,338	1,777

[a]Conventional plays are divided into subplays according to stacked stratigraphic units, each with an identical surface aerial extent. Conventional subplays thus were used for calculating resource amounts and costs but were not distinguished spatially. Tight sandstone plays are divided into subplays according to depth intervals (depths listed in feet). Tight sandstone subplays have unique surface aerial extents and thus were used for calculating resource amounts and costs and were distinguished spatially. There are 50 subplays used to define resource amounts and costs, 33 of which are distinguished spatially.

[b]Liquids = crude oil plus natural gas liquids.

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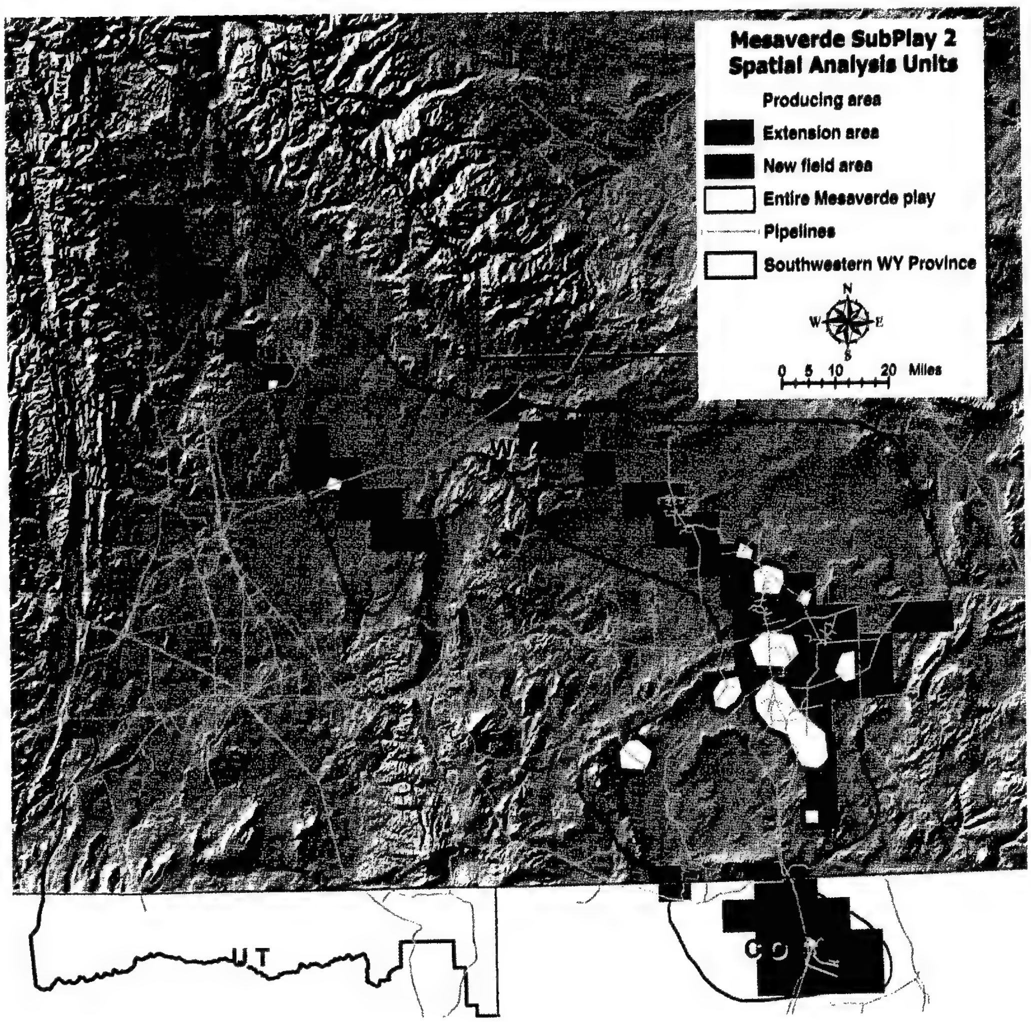
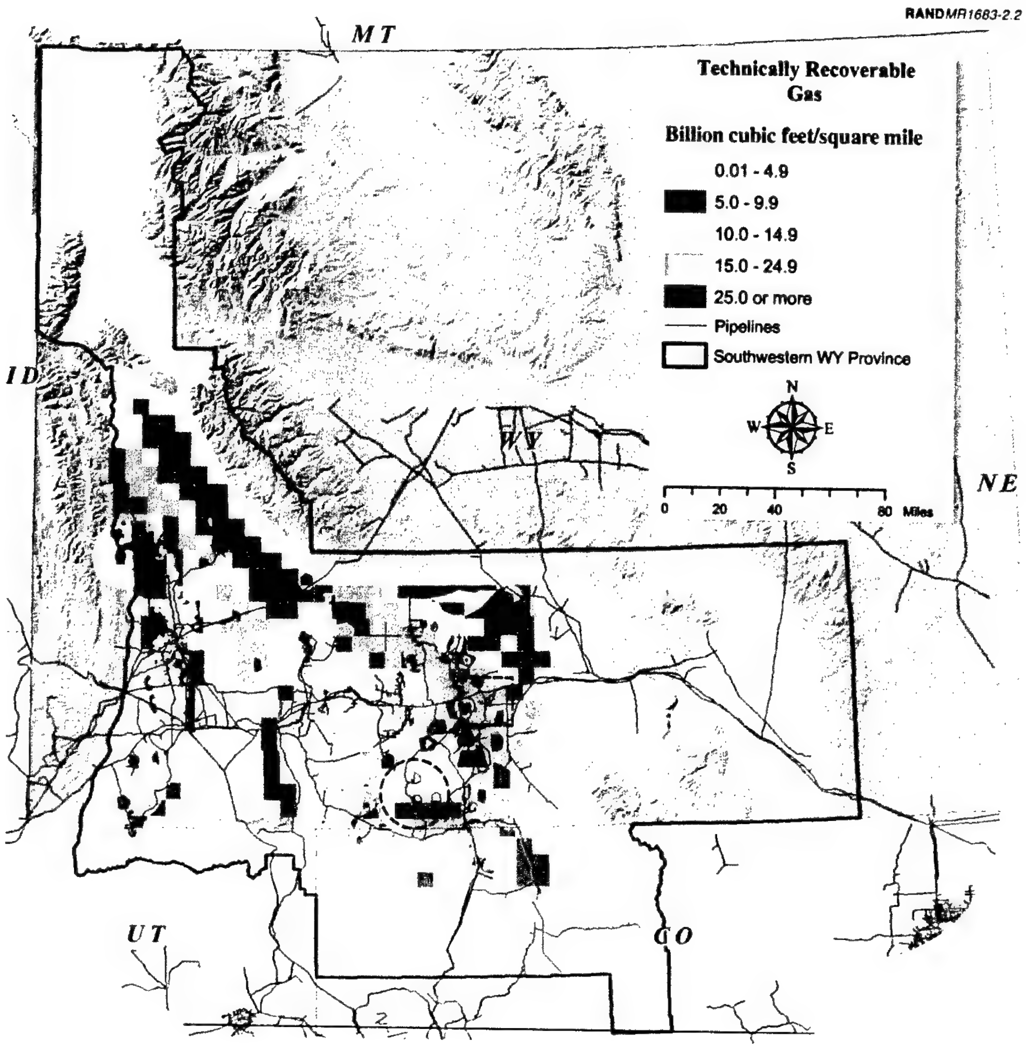


Map 2.1—Producing, Extension, and New Field Areas in Mesaverde Subplay 2



Map 2.2—Distribution of Technically Recoverable Resource for Greater Green River Basin from USGS-Based Scenario

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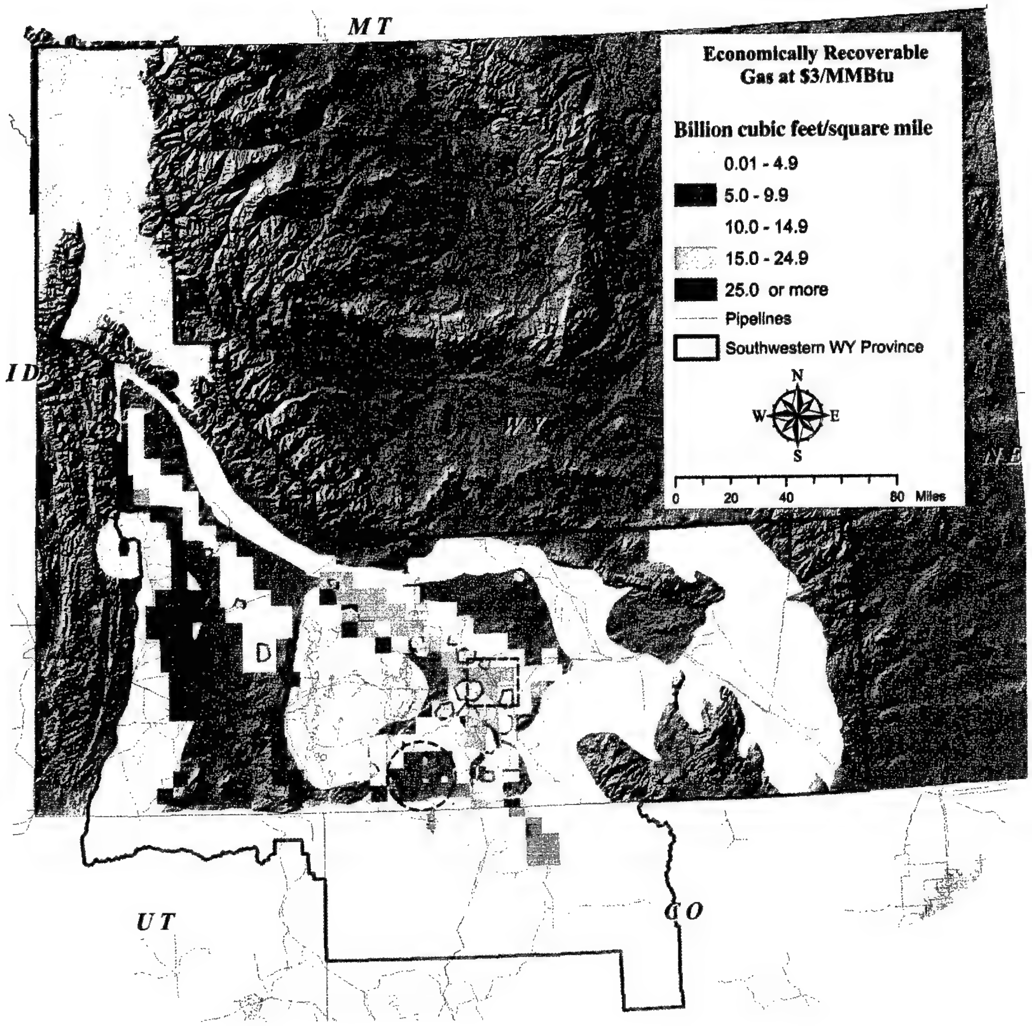
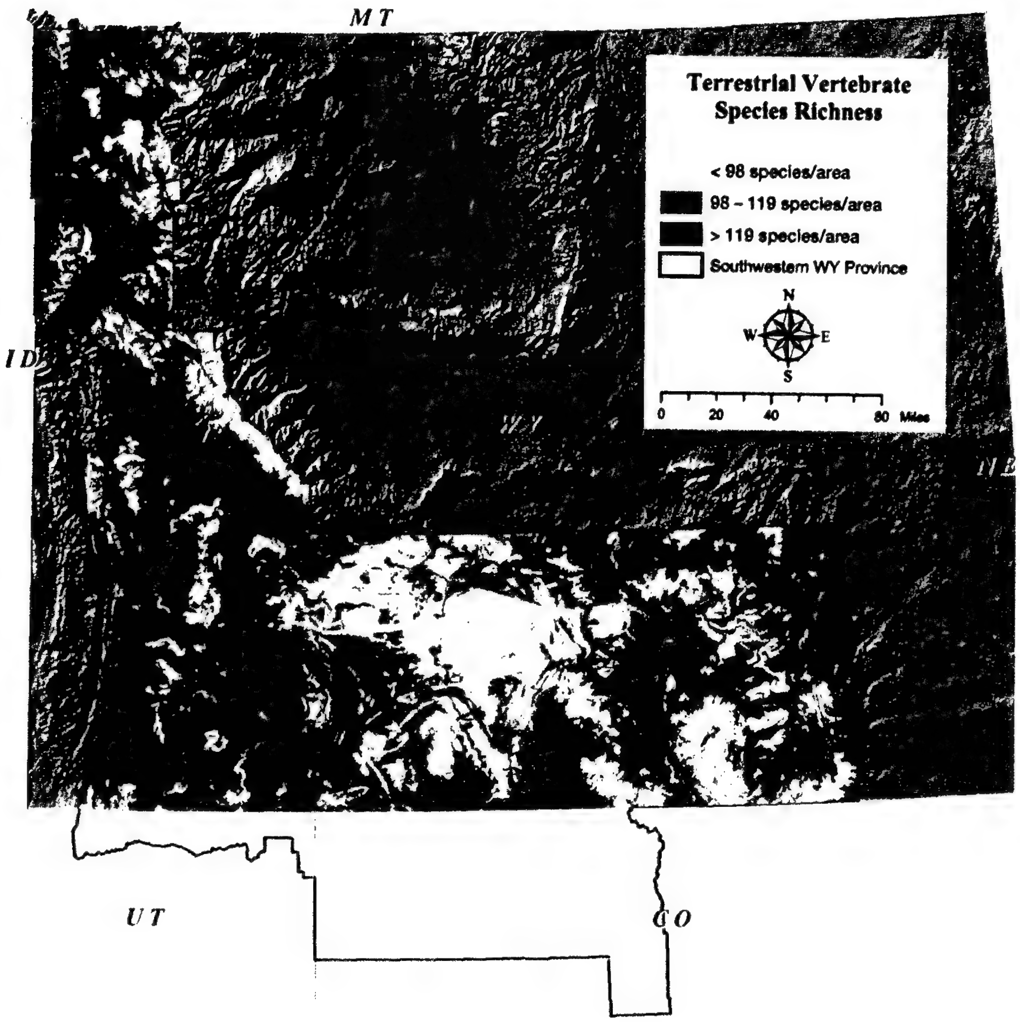


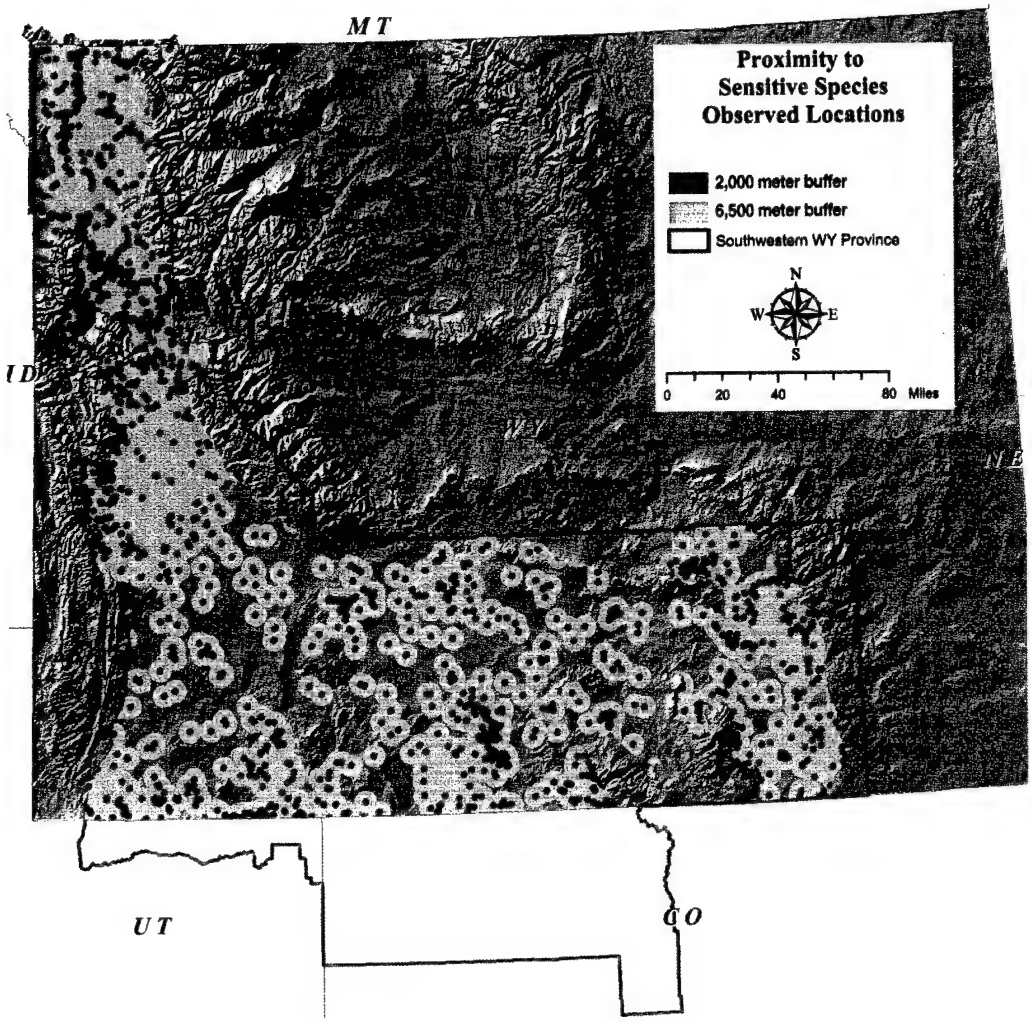
Map 3.1—Distribution of Economically Recoverable Resource at $3/MMBtu for Greater Green River Basin from USGS-Based Scenario

RANDMR1683-m4.1



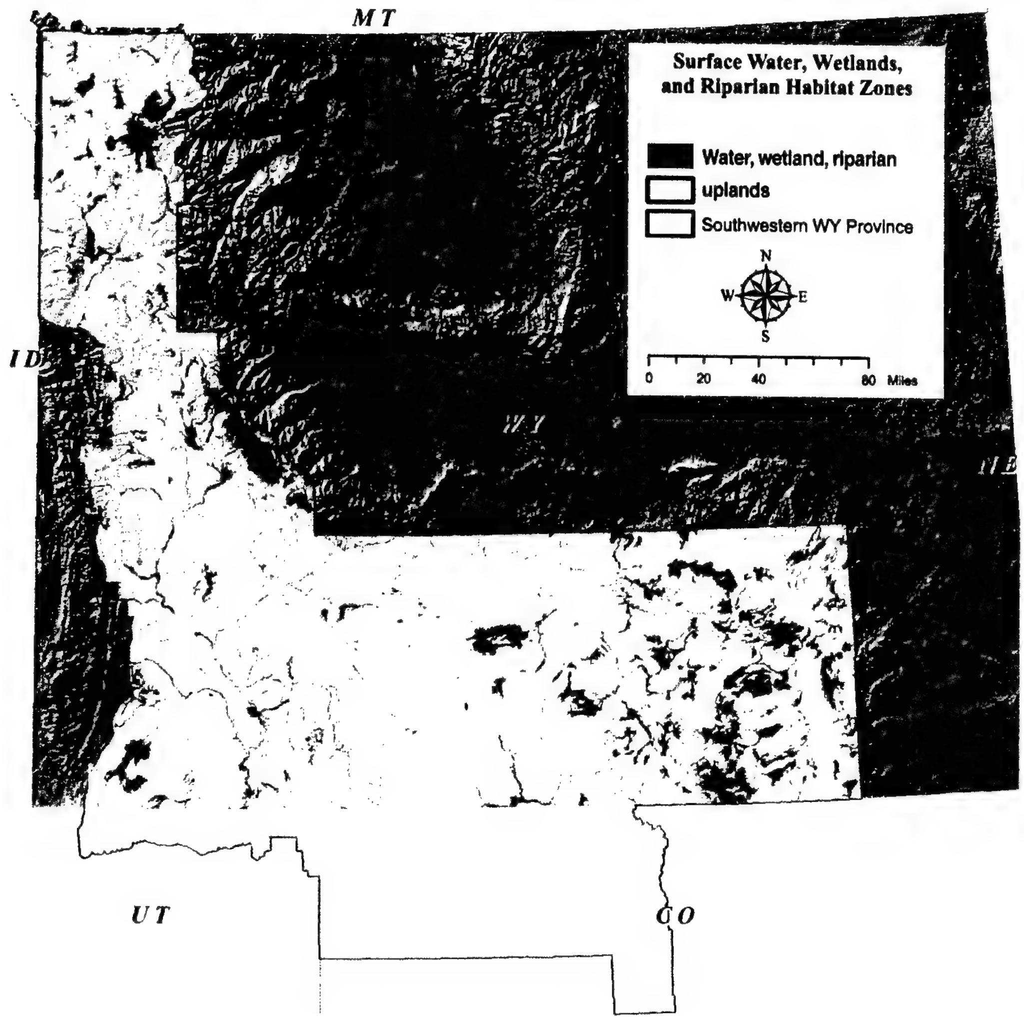
Map 4.1—Terrestrial Vertebrate Species Richness in the Greater Green River Basin

RANDMR1683-m4.2



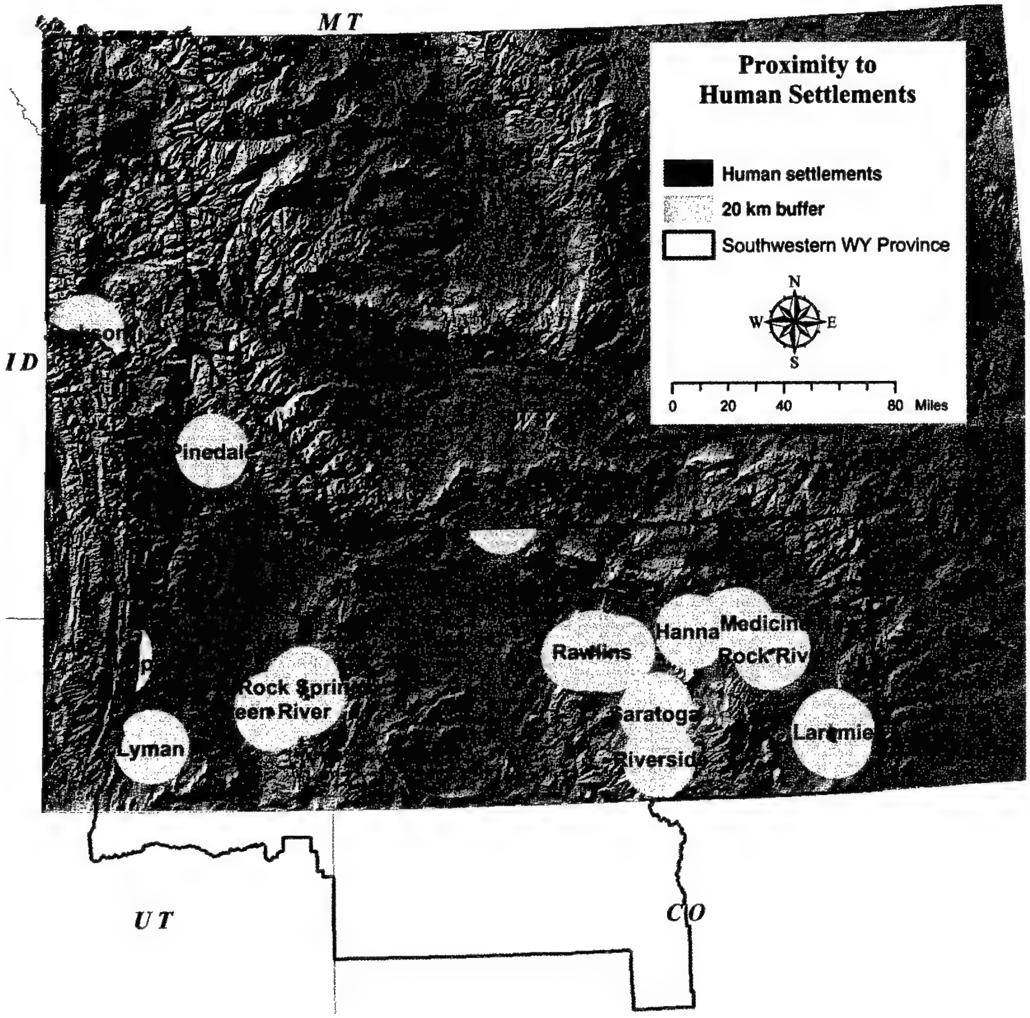
Map 4.2—Proximity to Sensitive Species Observed Locations in the Greater Green River Basin

RANDMR1683-m4.3



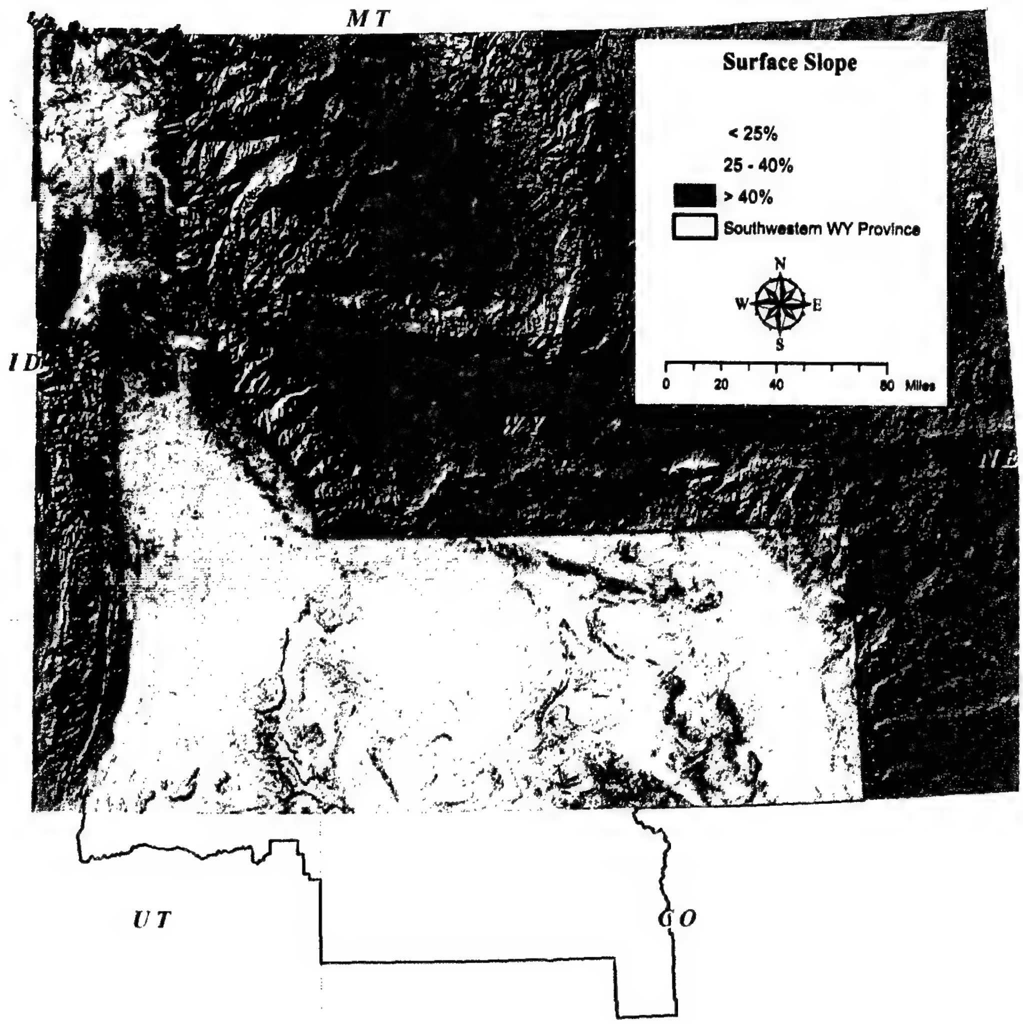
Map 4.3—Surface Water, Wetlands, and Riparian Habitat Zones in the Greater Green River Basin

RANDMR1683-m4.4



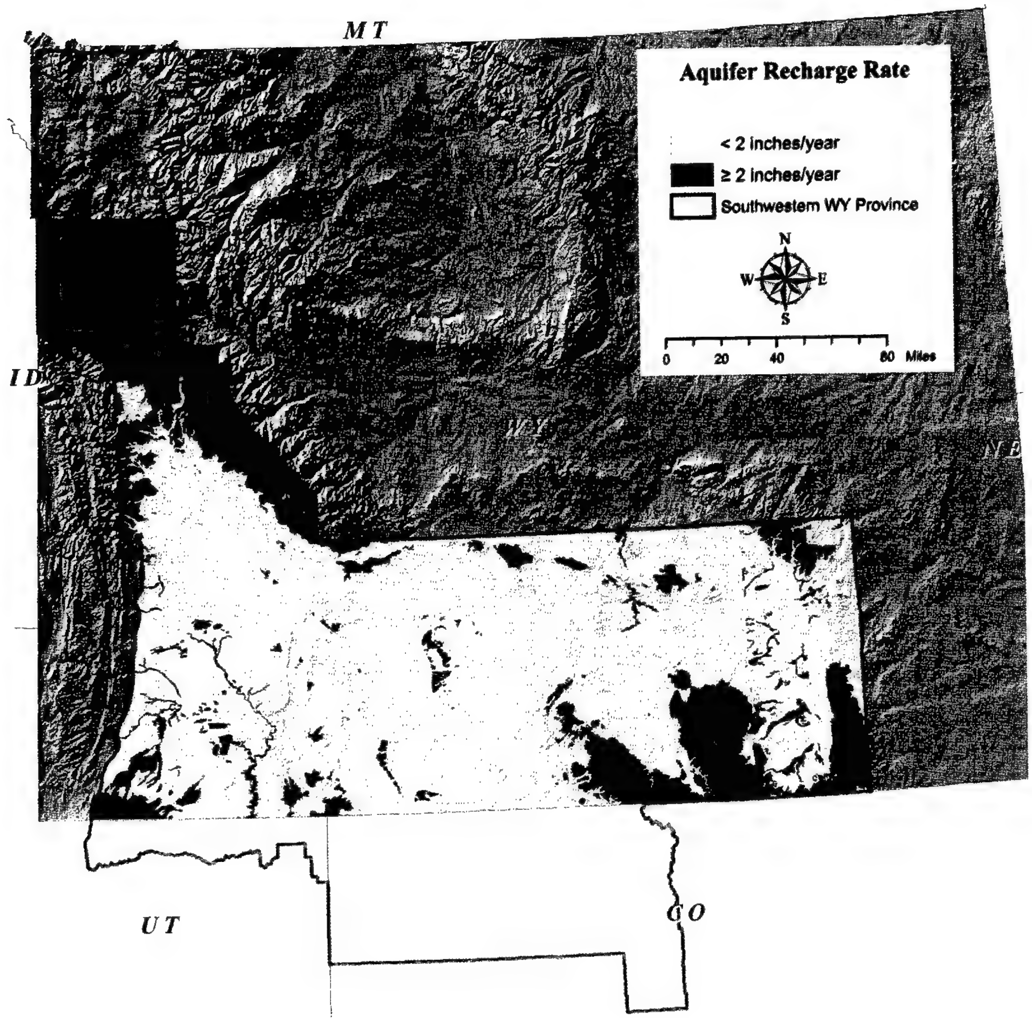
Map 4.4—Proximity to Human Settlements in the Greater Green River Basin

RANDMR1683-m4.5

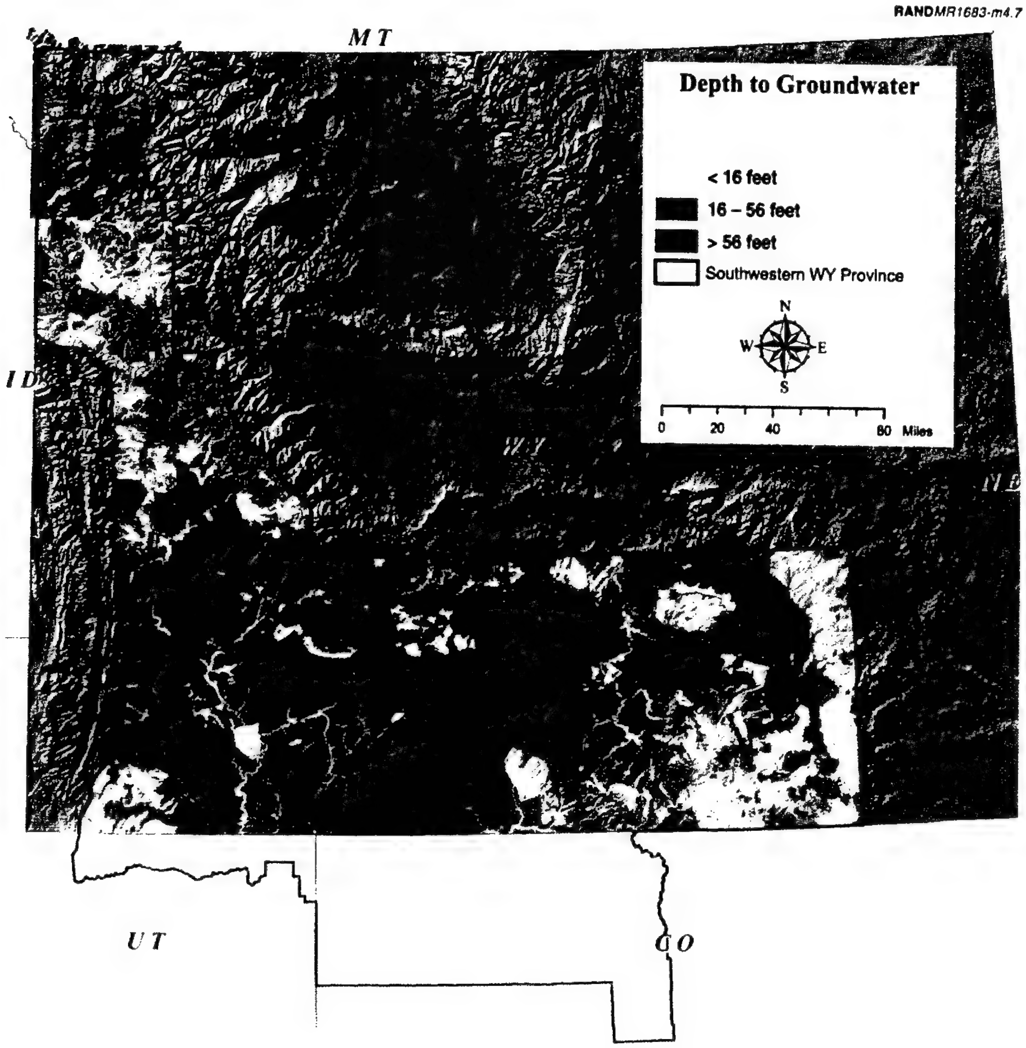


Map 4.5—Surface Slope in the Greater Green River Basin

RANDMR1683-m4.6

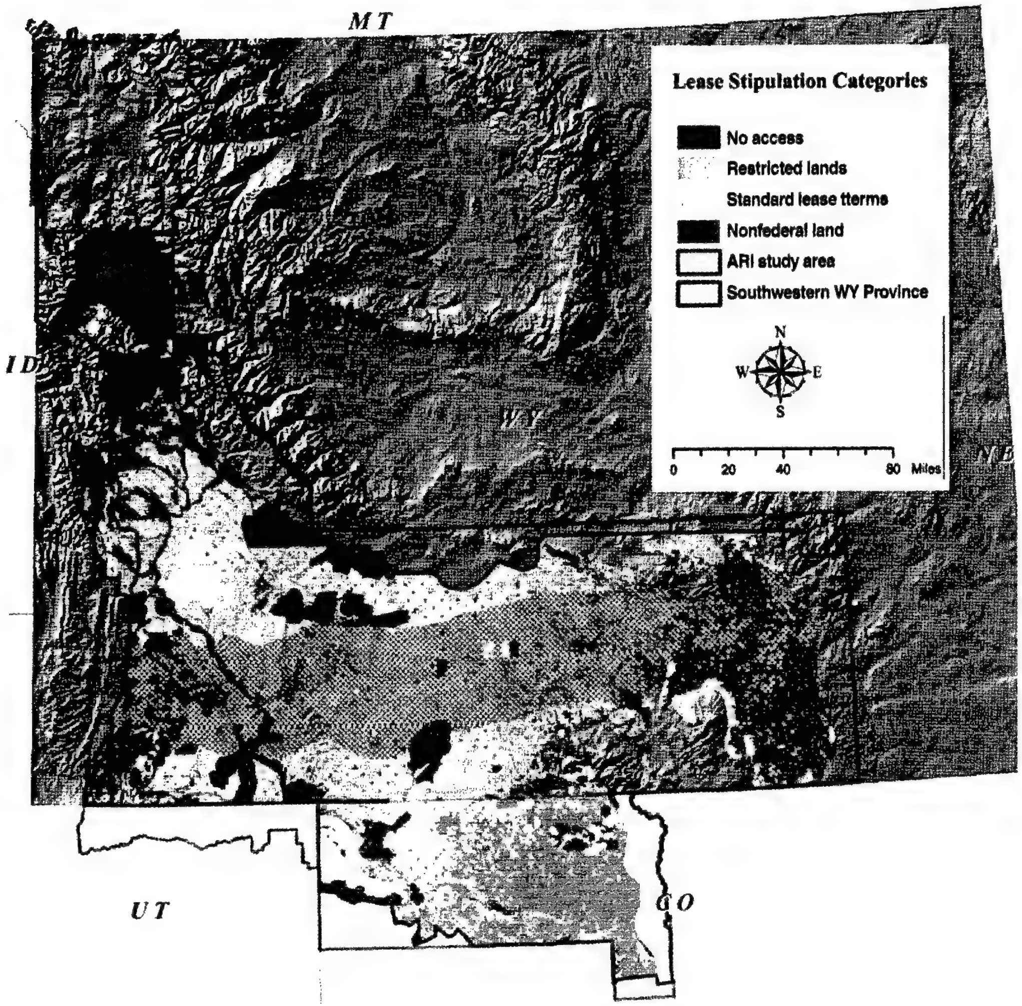


Map 4.6—Aquifer Recharge Rates in the Greater Green River Basin



Map 4.7—Depth to Initial Groundwater in the Greater Green River Basin

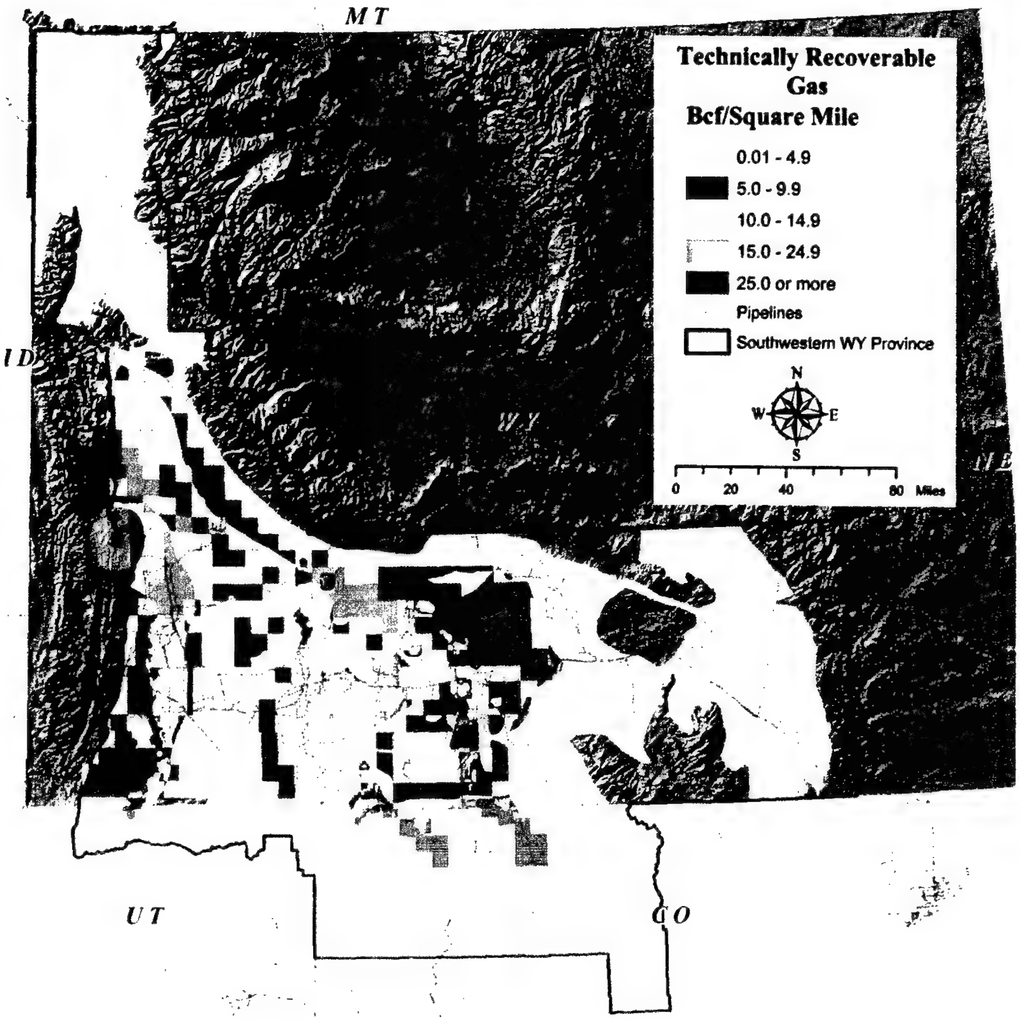
RANDMR1683-m4.8



SOURCE: Distribution of lease stipulations is taken from Advanced Resources International (2001).

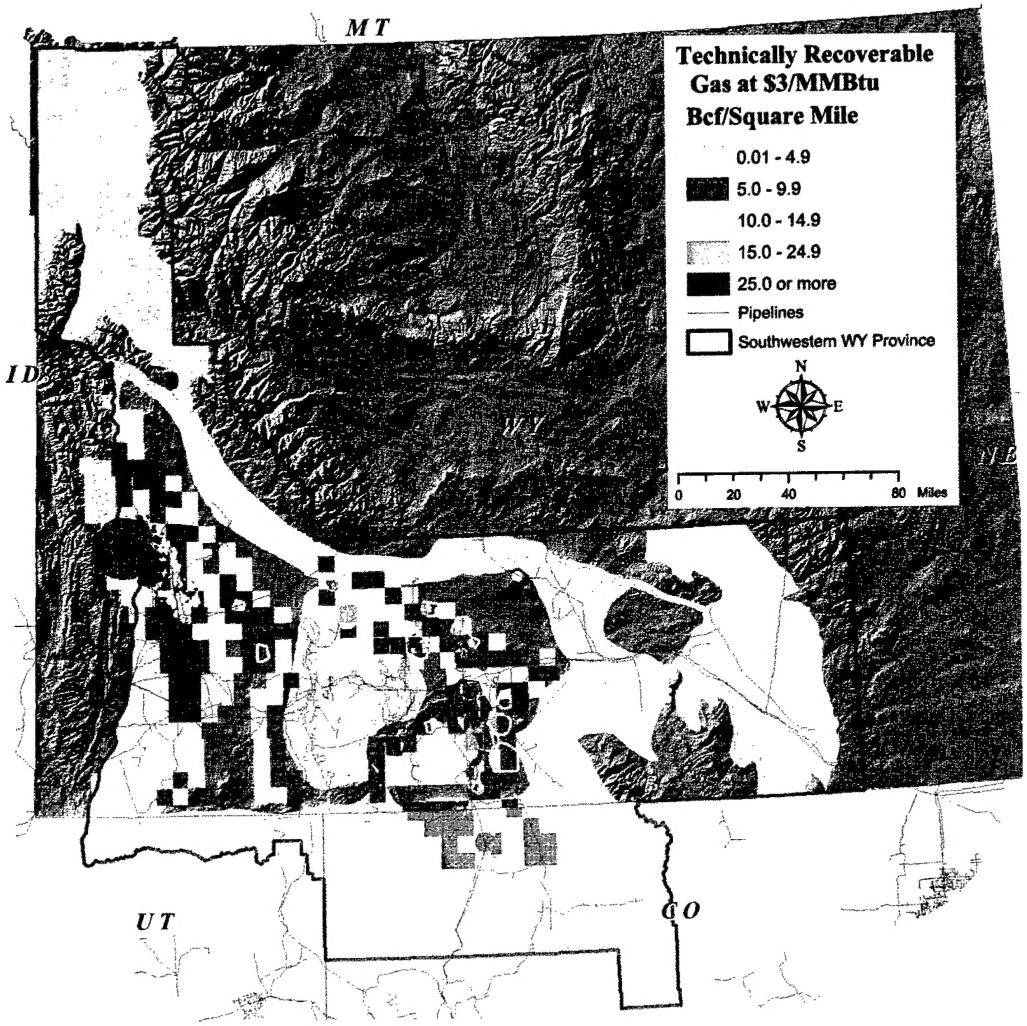
Map 4.8—Federal Land Lease Stipulation Categories in the Greater Green River Basin

RANDMR1683-mA.1

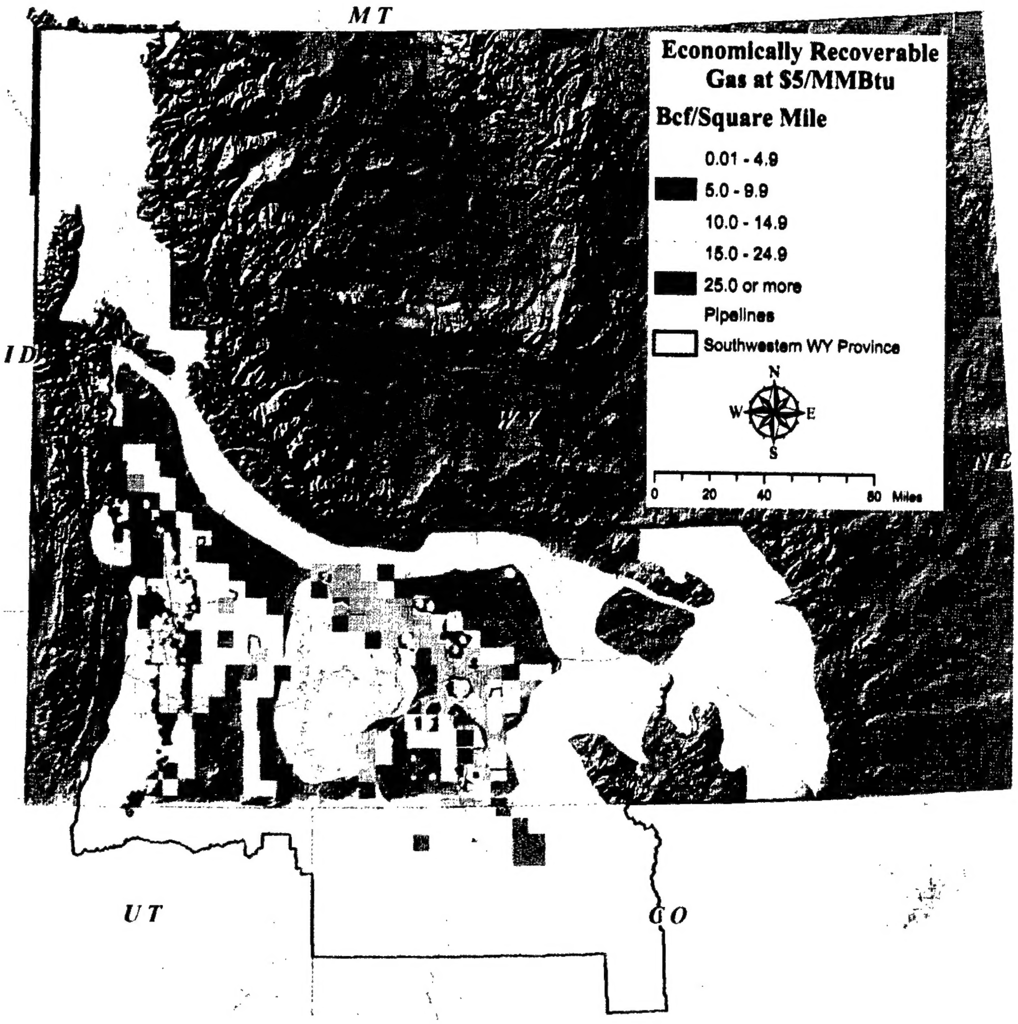


Map A.1—Distribution of Technically Recoverable Gas in the Greater Green River Basin for the NPC-Inspired Advanced Technology Scenario

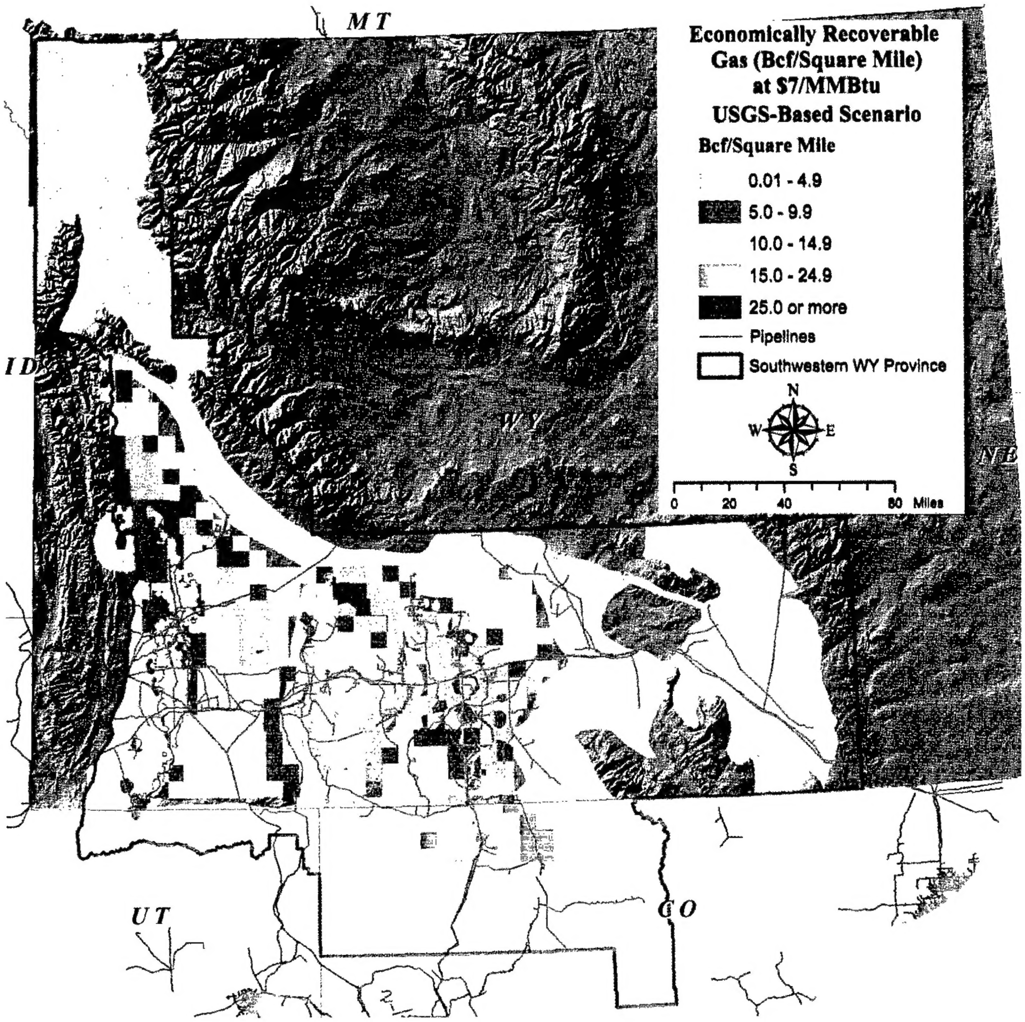
RANDMR1683-mA.2



Map A.2—Distribution of Gas Economically Recoverable at $3/MMBtu in the Greater Green River Basin for the NPC-Inspired Advanced Technology Scenario



Map A.3—Distribution of Gas Economically Recoverable at $5/MMBtu in the Greater Green River Basin for the USGS-Based Scenario



Map A.4—Distribution of Gas Economically Recoverable at $7/MMBtu in the Greater Green River Basin for the USGS-Based Scenario

NATURAL GAS DEMAND IN THE UNITED STATES is projected to increase by 50 percent over the next 25 years, and most of this demand is projected to be met by increasing domestic production. Much of the nation's future natural gas supply is located on federal lands in the intermountain west. Consequently, demands on federal land managers to open western lands for energy exploration and development are increasing rapidly. This report presents a new approach to assessing natural gas and oil resources that is intended to help federal land managers with strategic land use planning by expanding the scope of these assessments to include economic and environmental considerations. This approach provides a robust understanding of energy resource characteristics by accounting for the economics associated with production and by moving some of the environmental characterization steps upstream in the decisionmaking process. This will allow land managers to better distinguish energy resources in different areas and therefore help prioritize areas for consideration for energy resource development. The approach is demonstrated for the Greater Green River Basin in Southwestern Wyoming, which is estimated to contain about 9 percent of the nation's future natural gas supply.

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